THE 1970 NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION

PART I

FEDERAL POWER COMMISSION

OFFICE OF PUBLIC INFORMATION

CAUTION

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April 16, 1972

GUIDELINES FOR GROWTH OF THE ELECTRIC POWER INDUSTRY

THE ELECTRIC POWER INDUSTRY • STRUCTURE OF ELECTRIC POWER INDUSTRY • THE PROJECTED GROWTH IN THE USE OF ELECTRIC POWER • GAS TURBINES, DIESELS, AND TOTAL ENERGY SYSTEMS • TRANSMISSION AND INTERCONNECTION • DISTRIBUTION SYSTEMS • COORDINATION • POSSIBLE PATTERNS • REGULATION OF THE ELECTRIC POWER INDUSTRY • ECONOMIC PROJECTIONS • RESEARCH AND INVESTIGATION REQUIREMENTS • FUELS AND FUEL TRANSPORT • FOSSIL-FIRED STEAM-ELECTRIC GENERATION • NUCLEAR POWER • HYDROELECTRIC • OTHER FORMS OF GENERATION • COOLING WATER NEEDS AND SUPPLIES • AIR POLLUTION • ESTHETICS AND ENVIRONMENT • UTILITY PRACTICES AFFECTING RELIABILITY OF SUPPLY • PROBLEMS IN TIMELY PLANNING AND CONSTRUCTION • FINANCING THE GROWTH OF THE ELECTRIC POWER INDUSTRY

THE 1970 NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION

PART I

A REPORT BY

THE FEDERAL POWER COMMISSION

U.S. Government Printing Office
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PREFACE

The National Power Survey of 1970 has been a massive undertaking in which the Federal Power Commission has had the aid and cooperation of all segments of the United States electric power industry, many governmental agencies and concerned individuals. The report projects electric load growth over the next twenty years, and discusses changing power technology, growing concerns for all developments, including use of resources and various impacts on air, water and land, increasing problems in meeting schedules for needed new power facilities, power plant fuel supply problems, and the probable effect of these on the cost of power.

Shortly after the last National Power Survey was completed in October 1964, work on the present survey was initiated with the appointment of a reconstituted executive advisory committee, an advisory committee on underground transmission, a committee on reliability of bulk power supply, and six regional advisory committees to aid in load growth analysis, coordination among utilities, studies of increased power supply, planning for additional generating facilities, and reliability of bulk power supply. Later, technical advisory committees on generation, transmission, distribution and load forecasting methodology and a task force on environment were established. The membership of these committees and of the task force was broadly representative of all segments of the electric power industry and of groups in government, the electric utility industry and the public concerned with environment. The members of all of these groups are listed at the end of this volume.

While acknowledging with gratitude the assistance rendered by these groups, the Commission alone takes responsibility for its report.

The National Power Survey is reported in four parts. Part I contains the report of the Commission and the independent report of the Task Force on Environment. Parts II and III contain the reports of the six regional advisory committees. Part IV contains the reports of the technical advisory committees on generation, transmission, distribution and load forecasting methodology. Two advisory committee reports, *Underground Power Transmission,* April 1966, and *Prevention of Power Failures,* Volume II, June 1967, have been given wide distribution as separate publications.

The Commission's report is intended to serve as a general long-range guide rather than a directive or firm plan. It illustrates possible patterns of efficient development based upon assumptions outlined in the report and with the passage of time, modifications to reflect variances from the assumptions will be in order. For example, if fast breeder nuclear reactors should be developed earlier than the present target dates, or if the price of fossil fuel should increase more than projected, the estimated generation from fossil fuels in 1990 might be diminished. In a reverse situation, the use of fossil fuel generation might be increased.

For a closer look at the problems and opportunities during a more immediate period, attention is invited to the reports being filed annually with the Commission by the nine Regional Electric Reliability Councils, responsive to Commission Order No. 383-2 issued April 10, 1970. These reports include esti-

mates of loads, and projections of generation and transmission facilities to be installed by all segments of the industry for a ten year period into the future.

The Commission expects to make timely supplements to the National Power Survey within the limitations of appropriated funds so that there will be a continuing assessment of electric power needs and capabilities in the United States.

John N. Nassikas
Chairman

John A. Carver, Jr.
Vice Chairman

Albert B. Brooke, Jr.
Commissioner

Pinkney Walker
Commissioner

Rush Moody, Jr.
Commissioner

December 21, 1971

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CHAPTER 1—SUMMARY

Assessment of the U.S. Electric Power Situation

General

Mounting demand, sharply rising costs and changing social values have combined to place unusual stresses on the U.S. electric power industry. This is evident from the strained power supply conditions in many parts of the country and from numerous current proposals for increased rates. The Federal Power Commission believes that these developments, serious in their own right, may be merely a prologue to future events. We foresee recurrent and spreading power shortages unless positive steps are taken, and taken soon, to remedy conditions which are slowing the orderly development of essential power supplies. Similarly, we foresee electricity prices forced to rise, rather than decline as has been the general experience in the past. The cost pressures that result from ever more rigorous environmental protection criteria can only be partially offset by technological advances, and we see no significant relief from the upward market pressures on fossil fuel costs and the effects of general cost inflation. Since utilities have a large base of embedded capital investment which acts to dilute the immediate effect of inflated investment in new facilities, and also because of time lags in rate adjustment procedures, the unusually severe cost increases experienced by utilities over the past several years are just beginning to be translated into rate increases; thus their full and inevitable impact remains to be felt by the consumer.

It is already too late to avoid some further difficulties. Power facilities cannot be built overnight and so it will take time to correct present inadequacies in generating capacity and transmission. While the pattern varies across the country, the outlook for the several years immediately ahead is largely fixed by the momentum of past events. What is highly uncertain, and in our judgment critical, is the longer range outlook. Simple extrapolation of the many problem areas of the moment would lead to a bleak long-range outlook. If, however, the pluralistic industry, the increasingly active citizen groups, and diverse governmental interests all face these problems realistically, avoiding simplistic approaches to intrinsically complex matters, there is reasonable prospect that the challenge of the nation's power needs can be met.

None of these individual problems is either unique or unmanageable. It is, however, the present concurrence of manifold problems and opportunities (discussed hereafter) and the broad range of their effects which now challenge this largest of the nation's industries as never before. It is therefore timely and essential that the public see the overall picture in the clearest possible form.

Areas of Problems and Progress

There are many reasons for the tangled picture of the moment. New and needed power capacity has been delayed by such varied factors as: manufacturing quality control; labor disputes and low productivity at plant sites; inadequate forecasting; insufficient advance public disclosure; changing regulatory standards; inadequate research and development; litigation and licensing delays. Most of these problems can be solved. But another prime reason for concern about the future is that contradictory public attitudes about electric power are presently on a collision course. Today, as in the past, the demand for electricity is growing at a faster rate than the population and the national economy, and requirements for new power facilities are therefore constantly growing. At the same time, and despite increasing efforts of public agencies and the industry itself to protect the environment, today more than ever before the construction of new power facilities is being challenged

on environmental grounds. Some vitally needed power projects have been delayed or blocked on this account while the growth in demand for electricity has continued unabated. Something has to yield in such a situation, and what has been yielding has been the margin of assurance of electrical service. Voltage reductions and a few localized blackouts occurred in several of the nation's major urban areas during recent years when utilities were obliged to reduce or shed load during peak demand periods to avoid system overloading. The end is not yet in sight in certain critical areas, although in the most critical areas generating reserves have improved during 1971 and will continue to improve if current construction projects can be completed on schedule.

To see this problem in proper perspective it is important to keep in mind the fact that the job of supplying electricity involves some rather special considerations. One stems from the fact that, unlike most other staples used in daily life, electricity cannot be stored on the shelf to be drawn upon as needed. Quite literally, it must be produced on demand—i.e., generated, transmitted and distributed in the precise amounts utility customers require and at the precise time they summon it. Further, this is essentially an instantaneous process with only milli-seconds elapsing between the time raw energy is converted into electricity at the power plant and the time that same electricity is delivered to the consumer, be he tens or even hundreds of miles away.

The total instantaneous demand—i.e., the sum of the needs of all of the utility's customers at a given instant of time—is highly variable, tending to be at its lowest point in the early morning hours, to build up during the day, and then taper off as night approaches. It is different on weekends than on weekdays, and varies also with the changing seasons. Nationally, there is diversity of demand among regions. In the rare situations in which a utility has had insufficient operable plant capacity to meet its peak demand and cannot fill the gap by drawing on the reserve capacity of other systems, the utility—if the gap is small enough—may be able to bridge it by calling for voluntary curtailments or by reducing the voltage at which it supplies electricity to its customers. Such measures have the effect of spreading the available amount of electricity among the utility's customers, and if the voltage reduction is small, it generally has no significant effect on most of the uses electricity serves. However, utilities cannot reduce voltage beyond a certain point for too long a time, lest electrical appliances designed to operate in a narrow voltage range be damaged. If a utility reaches the point where it cannot safely reduce voltage enough to bridge a supply gap, it has no alternative but to shed load—i.e., temporarily to discontinue distribution to a particular class or locality of service. When this step must be resorted to, it is normally done in accordance with a pre-established contingency plan which takes into account priorities of community and human needs and efforts are made to distribute the burden as uniformly and equitably as possible, with a minimum of inconvenience.

Thus under strained conditions following voltage reduction a utility has various limited remedial steps, including appeals for voluntary curtailment. But with respect to any one customer, the supply options are either to furnish essentially all of the electricity the customer calls for, or, when a shortfall of capacity so requires, none of it. There is no in-between.

A second special consideration affecting the job of supplying power is the fact that it takes a number of years to plan and build major power facilities, during which time the demand for electricity grows. The relationship between the amount of reserve capacity usually maintained by a utility and the rate at which its system load grows is such that significant delays in the completion of major new generating units rapidly erode the utility's reserve margin and thereby weaken its supply capability and degrade the quality of its service.

Deterioration of the quality of electrical service is but one result of delays in building new capacity. Delays also impose substantial cost penalties. They extend the period over which utilities must carry the burden of fixed charges on investment in uncompleted and therefore non-productive facilities; they prolong utility exposure to construction cost escalation; and often they necessitate expensive substitute power supply arrangements. These extra costs are incurred by the utility but in the final analysis it is the electricity consumer who pays the bill.

The concern of the public and the industry about environmental questions is affecting

power costs in other, more direct, and even more substantial ways. For one, utilities must spend progressively larger sums on environmental protection and appearance-improving features of power installations. For another, the fossil-fuel sources on which they can draw are being progressively narrowed by regulations requiring the use of low-sulfur fuels, which are presently in short supply and have been commanding stiff premiums. It may well be true, as some contend, that the public is prepared to pay substantially more for electricity in the interests of reducing the environmental effects of power operations, and, if so, the price effects of these new costs may be accepted by the rate payer without serious challenge. As matters now stand, however, not enough time has passed for the true impact to be felt and so the question is still at issue. It will take even more time to obtain conclusive experience with the protective measures being taken. Thus in these fundamental respects, as well as in the economic side effects, the outlook is not clear. And, it is already clear that the consequences flowing from the Calvert Cliffs decision (requiring the Atomic Energy Commission to review all environmental aspects of nuclear power plants) of July 1971 [1] cannot yet be fully measured in terms of the added time for analyses and procedures and, perhaps, added environmental controls needed to conform fully with the National Environmental Policy Act of 1969. Furthermore the nation's electric power program of the next two decades is critically dependent on successful introduction on schedule of tremendous increments of nuclear power.

The cost pressures stemming from the inflationary trend of the national economy and the fossil fuels market have been further compounded by the trend of higher environmental costs. The unusually high interest rates of the past several years and the still-continuing rapid escalation of construction costs have had heavy impact on the power industry (the most capital-intensive and one of the fastest growing of all major U.S. industries). There is some offset in the prospect of long-term fixed investments being paid off in dollars of declining value.

Fortunately, there is a positive as well as a negative side to the present electric power situation. The technology of power continues to show remarkable vitality, and there has been a great deal of solid industry accomplishment in recent years. System inter-connection and power pooling has been greatly strengthened with resulting increases in reliability. Through combined industry effort and coordination under the Federal Power Commission's Order No. 383–2,[2] the planning of system expansion is now beginning to be approached on a more highly coordinated basis. Rapid progress has been made in the application of nuclear power to base-load generating service, and there has been progress in use of pumped storage and gas turbines for peaking service. Gains have been made in extra-high-voltage power transmission, in design of transmission towers and distribution substations, and in the undergrounding of distribution lines. Many of these advances contribute importantly to improved environmental quality. Additionally, there is a new awareness of the vital importance of research and development, and there are signs that the industry is recognizing the need for larger expenditures and greater utility involvement in research and development (R&D). The Report of the R&D Goals Task Force to the Electric Research Council is a noteworthy step forward.[3] Also, though it sometimes seems to take the form of obstructionism, the new and more active interest the public is displaying in power matters is of itself a positive development and hopefully will lead to a constructive joint relationship between industry and the public in resolving the complex issues of the future.

In summary, the health of the electrical industry is today basically sound, although menaced in some areas of the country by current and increasing delays in new capacity additions. Thus it will take the best coordinated efforts of the industry, the government, and the general public to prevent this potential threat from proving real; in this perspective the common sense of the average citizen, as much as any other factor, may be the key.

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[1] *Calvert Cliffs Coordinating Committee, Inc.* v. *AEC*, No. 24, 839 (D.C. Cir., July 23, 1971).

[2] Order Number 383–2, issued April 10, 1970, relates to Reliability and Adequacy of Electric Service—Reporting of Data—Participation of Regulatory Personnel in Regional Councils.

[3] Electric Utilities Industry Research And Development Goals Through The Year 2000. June 1971.

Why Quality of Service is Critical

So far many of the factors we have cited (which might degrade future quality of service) have been fairly countered by current measures such as: alternate plans; adjustments in schedules; postponements of plant retirements; changes in fuel use; and narrowing of reserve margins in some regions. These responses and degrees of resilience may have led the public to feel that the power industry (because it has continued generally to serve reliably and adequately) has almost limitless capacity to adjust to any series of contingencies thrown upon it. This is a perilous assumption.

The critical nature of the industry's position in relation to the country's energy needs suggests that the public must be more keenly aware of what would be the most serious consequences if a condition of diminished capability were to grow and spread unchecked by curative measures.

The mildest phase of such a process would be an increase in the frequency and extent of voltage reductions as utilities with inadequate reserve capacity found it increasingly necessary to take this step to protect against overloading strained facilities. The argument is sometimes made that it would be better from the environmental standpoint for the power industry routinely to operate on the basis of reducing voltage at times of heavy demand than to build the additional capacity needed to accommodate the demand peaks. Aside from the fact that this would mean that the industry would then always be on the razor's edge during peak demand periods, it follows from the earlier discussion of the limitations of voltage reduction that this approach could at most reduce plant capacity requirements by about 5 percent, which for an industry growing at a rate of 6 or 7 percent per year is equivalent to less than one year's normal expansion requirement.

So reliance on such measures could only lead to an increase in the frequency of temporary local blackouts as utilities increasingly found it necessary to shed load at times of peak demand —i.e., to cut off the supply of electricity to some customers or to particular localities. If this trend continued unchecked—which we believe most unlikely and indefensible, the next phase would begin when utilities had to discontinue service so frequently or for such long periods as to interfere seriously with the operations of industry and commerce, cause food spoilage in inoperative refrigerators and the like, with consequent measurable effects on the economic health and residential well being of the community. Investor confidence in the future of the industry would have begun to weaken and potential difficulties in raising capital to finance plant modernization and system expansion could further accelerate the rate of deterioration of electrical service. The results in driving electricity prices upward (with rate increases necessary to cover higher financing costs and lower efficiency of their operations) would compound the effects of slowing the machinery of the national economy, since reduced electrical service would discourage business expansion, new home construction, and all the collateral activities on which economic health depends.

These potentials are such that no one—not the industry, not the public, and not government—would willfully allow these things to happen; yet they *could* happen. They could happen for the simple reason that, like the human body, the nation's power generation, transmission, and distribution network is a complex system which can cease to function effectively if any of its component parts get seriously out of adjustment or if its basic metabolism goes awry. Clearly, also, if the quality of electrical service *did* seriously deteriorate, the impact on the nation's economy and standard of living would be massive and far reaching.

One of the landmarks of progressive social legislation is the National Environmental Policy Act of 1969. In the language of this statute the central objective is defined as protection of "the quality of the human environment." This phrase encompasses man's need for energy as well as his need to protect the natural environment. Apart from those few who, heedless of the implications and oblivious to the impracticality of trying to put an industrialized society to pasture, take a "who needs it?, let's go back to nature" attitude toward electricity, no one these days questions the importance of this highly adaptable form of energy. Not many, however, consciously appreciate how fundamental electricity has become to the "human environment" and how importantly it affects the nation's economy as well as its quality of life. The latter is the

more obvious because it is the more visible. Electric lights, electrically energized heating and air conditioning, and basic electrical appliances such as refrigerators, vacuum cleaners, washers and dryers, power tools, dishwashers, elevators, operating rooms, television and "hi-fi" sets have become so much a part of the fabric of twentieth-century living that it is inconceivable that they would be given up willingly or without drastic impact on our society. Even so, the changing dollar and social cost values associated with future electrical service emphasize the need to examine any realistic potentials for conservation of electric energy.

Electricity's importance to the national economy is equally fundamental. To a very considerable extent the nation's industry and commerce literally run on electricity. The electric motor, the telephone, the computer, and most of the devices used to control industrial operations could not function without it. Several key industrial processes such as electrolysis and electrorefining could not be carried out without it. Quite apart from this dependence on the use of electricity, a close relationship exists between adequacy of electric power supply and the economic health of the nation at large. Although electrical sales do not account for a very large fraction of the gross national product (2.3% in 1970), each worker's high utilization of energy is the essential reason for his high productivity, which, in turn, is the basis for our high standard of living. Moreover, the power industry is by far the largest investor in plant and equipment of any of the nation's industries, accounting for about 12 percent of all new investment in plant and equipment annually. It therefore has an important influence on national financial trends.

Deterioration of the quality of electrical service would of itself and through its economic repercussions degrade our national life. That is the crux of the power issue facing the nation today and should be borne in mind by all who participate in shaping the industry's future course. In a very real sense electric power is the lifeblood of a modern nation.

Axiomatic to this point is another—namely, that it is one thing to take electricity for granted, as all of us have come to do in our daily life, but quite a different thing to take for granted that it will always continue to be available.

Major Need and Imperatives

In projecting our views on these critical matters, we caution the reader that any of our present estimates or conjectures of the future may be markedly changed by factors already at work. These include: the possible kinetic effect of an accelerated pace of research and development; the development of more crystallized national energy policies; and the already accentuated pace of change in the industry. Nevertheless, from our vantage point, and with the benefit of the findings set forth in this report, we of the Federal Power Commission assess the major imperatives of the national power situation as follows:

The need to recognize the situation for what it is: The first imperative is for the American people to recognize that the problems facing the power industry today are of a critical nature and that it is the nation's and their well being as individuals, not merely that of the industry, which is at risk.

The need to distinguish between short-range problems and long-range objectives: Too often these days those who oppose the construction of new generating stations or transmission lines blur together two quite separate considerations —(1) the specific effects the particular installation will have on its environs, and (2) the potential environmental impact of building a large number of equivalent installations over a long period of time to meet projected demand growth. As a result, urgently needed power facilities are often delayed by issues that belong in the realm of long-range policy making. The operative words here are "urgently needed." There are many utilities today that have inadequate reserve generating capacity or inadequate interties with neighboring systems. They are being hard pressed to keep up with rising demand and this problem is being exacerbated by delays in obtaining necessary licenses and clearances for critically needed system additions. The momentum of short-term demand growth and the long lead times required for the planning and construction of major power facilities are such that delaying critically needed facilities generally serves only to aggravate both environmental and power supply conditions. The delay forestalls

the retirement of technically and environmentally obsolete facilities, forces the postponement of normal plant maintenance, and leads inexorably to higher forced outage rates and further erosion of reserve margins. In short, the urgency of correcting existing or imminent power supply inadequacies needs to be recognized as a matter separate and distinct from designing future facilities and controls to meet new requirements, and this distinction must be appropriately reflected in current licensing and certification criteria and procedures.

A matching imperative is that in planning for the future, utilities allow for longer lead times and modified techniques of site planning, review and certification. They must support the levels of research and development and engineering effort necessary to ensure that each new power facility will be a better performer, environmentally speaking, than the one before it.

The need for improved site selection procedures: It is now apparent that the procedures generally followed in the past in selecting and developing power plant sites and related transmission rights-of-way are inadequate to present circumstances and future needs. Community interest in the sites to be used and in the manner of their development is now so widespread, and the issues of environmental concern are now so intensified, that it is essential to establish new siting procedures. These must provide adequate time and opportunity for public appraisal and community participation and at the same time must provide for orderly and authoritative decision making. Various proposals have been made for new federal legislation to govern the siting of major power facilities. Embodied in some or all of these proposals are a number of principles which have the support of some or all members of the Federal Power Commission and reflect discussions with other concerned agencies. These include:

1. Establish, through legislation at the state level, state or regional siting authorities;
2. Require utilities to make ample advance disclosure to these authorities of plans for new power plant sites and transmission rights-of-way including analyses of practical alternatives to proposed plans, together with the environmental consequences of each;
3. Provide mechanisms to permit timely and thorough review of these plans and alternatives by interested citizen groups;
4. Empower the siting authorities to carry out an expedited "one-stop" or single coordinated review of the site proposal in relation to both federal and state environmental protection requirements;
5. Empower the siting authorities to approve and officially certify that siting arrangement which is found to be acceptable in striking a reasonable balance between energy needs and environmental impact among the alternatives available; and
6. Provide a mechanism whereby such evaluation and certification can be done by a federal agency in the event of default of timely action at the state or regional level.

In moving to support major federal legislation along these lines, the Commission has concluded, firstly, that the issues between power supply needs and environmental protection are too important to be left to chance procedures, and, secondly, that better solutions can be found by balancing the specific pros and cons of individual situations than by attempting to impose generalized and inherently inflexible "prescriptions," which may not, and often do not, fit local conditions and circumstances.

The need for a national energy policy: It is now evident that the concurrence of increasing needs for energy, as well as the national need to improve our environment, emphasize the requirement for coordinated national policy development in both areas. The national demand for electricity has followed the pattern of doubling approximately every ten years. A further doubling of demand during the 1970's appears virtually certain and a growth rate only slightly less is presently indicated for the 1980's. This rate of growth far outstrips that of energy consumption in general. In 1960, 20 percent of the energy consumed in the United States was in the form of electric power. By 1980 electric power's share of national energy use is expected to pass the 30 percent mark and by 1990 it is expected to be about 41 percent.

There is beginning to be widespread concern about the long-range implications of this growth

pattern for electricity. This concern takes several forms. Some are concerned about the accumulative environmental effects; others, about the strain such growth would place on raw energy and land resources; and still others about the nation's ability to finance it. Each of these lines of thought leads to the same conclusion: the nation's resources—whether expressed as fuel reserves, the capacity of the natural environment to assimilate wastes, the availability of energy, land, or investment potential—are finite, not infinite. With electric power operations already having reached a giant scale, constant exponential increases can not be continued indefinitely. Sooner or later the rate of growth of electrical demand must either decline of itself or be reduced by external factors.

As already indicated, there is little likelihood that the rate of growth in electricity use will slow appreciably in the two decades immediately ahead. There are sound reasons for this outlook. For one, the growth projected for the next twenty years is largely foreordained by events that have already been set in motion. The children who will form the new families of the 70's and 80's are already here. Every new house, apartment building, shopping center office building, and industrial plant going up across the country, has a built in electrical demand, and for every one of these structures there is another already on the drawing board. Moreover, it is already clear that measures needed to upgrade the nation's environment are creating substantial new requirements for electricity. Examples are recycling scrap paper and metal to reduce the accumulation of solid wastes; sewage treatment plants to reduce water pollution; prospects for electrified rapid transit in large cities to reduce automotive congestion and air pollution; and power consuming devices to control pollution by power plants themselves.

For these and other reasons it is necessary to look beyond the immediate, or even the near-term, future to see any possibility of a significant decline in the rate of growth of electrical demand either occurring or being made to occur. Those who call for growth to be stopped immediately, as though the forces that govern electrical demand were a kind of faucet to be turned on and off at will, either do not appreciate or choose to ignore the strong momentum of our society. However, the same momentum that precludes changing the short-term electrical demand outlook makes it imperative that action be taken now to assess whether the longer range trend needs to be moderated, and if so, how this might be accomplished. This assessment cannot be meaningfully done within the frame of reference of electric power alone. Electricity is but one of the major energy forms in use today, most of which draw on common energy resources and any one of which is in some degree substitutable for another.

A reasonable transition period is required to examine this picture, develop an action program, and achieve results. Among the first needs is a comprehensive assessment of the long-range consequences of various possible patterns of energy consumption and use. This would provide a frame of reference within which energy questions could be viewed in proper perspective and thereby aid the formulation of appropriate energy priorities and balanced forward-looking energy development programs.

Relatedly, it is important that an overall assessment be made of the nation's environmental protection needs. Research on the ecology is not a new field but it has only recently taken on major proportions. There is as yet a general lack of conclusive answers to many of the questions being raised today about environmental effects, especially those involving the cumulative effect over a long period of time of subtle changes in natural conditions. Lacking background data on many ecological effects, the nation presently has no conclusive basis in many cases for making definitive cost-vs.-benefit judgments needed to ensure that environmental protection efforts are channeled along the most productive lines and in a manner consistent with the overall national interest.

These limitations in present knowledge must be carefully weighed in arriving at priorities for the energy field in general and for electrical energy in particular. The electric power industry's operations interact with all the principal elements of the environment that are troubling the nation today: air quality, water quality, land use, and resource consumption. In none of the problem areas is the industry uniquely responsible for the nation's pollution problems, and in some of them it is not even a major factor. Neither governmental authorities nor the public should gauge environmental measures solely in

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terms of the fact that power installations are large and highly visible to the public eye and, accessible to control, owing to the franchised structure and publicly regulated nature of the utility industry. The industry does not lack the means or the will to develop better solutions to its environmental problems. Still, the best efforts can only reduce, not eliminate, the environmental impact of needed electrical supply.

Until such time as the nation takes comprehensive inventory of its energy resources and environmental protection needs and priorities, there is the risk, from the overall national standpoint, that research and development efforts, environmental protection criteria and standards, and investments in environmental protection in different fields of activity may not be kept in proper balance. The nation cannot move overnight to correct all the environmental wrongs of the past or to implement all the environmental needs of the future. It would bankrupt itself if it were to attempt to do so, for the task is truly enormous.

The danger of serious imbalances, especially at this early formative stage of the nation's environmental crusade, is that when the costs begin to be counted and the true magnitude of the national needs begins to be appreciated, the public may be shocked into backing off from the undertaking, leaving some of the most important tasks undone. It would be tragic in the extreme if the heavy emphasis currently being placed on the environmental aspects of electric power should have this effect, or if, by failing to maintain a proper balance between environmental values and vital community energy needs, the end result is to diminish, rather than improve, the overall quality of the "human environment." In short, there are parallel national needs for development of power resources and for preservation or improvement of environmental resources. To these ends there is also a need for suitable governmental structures to provide a basis for achieving these objectives through an effectively functioning power industry. The policy bases at all levels should insure in each case balanced determinations after weighing both economic and environmental factors.

The need for intensified research and development: From what has already been said, it will be apparent that a key factor in the long-range outlook—and many believe *the* key factor—will be an accelerated rate of technological progress. Fortunately, there are several possibilities for major technical advances by the industry in this and the next decade, and even more possibilities for the longer range future. In the area of generating technology, the development of breeder reactors for use in commercial nuclear power plants, among other benefits, would vastly increase the nation's available nuclear fuel. Further, once its technical feasibility has been established, the development and use of controlled fusion, would make such fuels virtually inexhaustible. These or equivalent developments would also be important because a new technological base for an environmentally compatible power supply system must be found by the end of this century to ensure that anticipated growth in power demand will be accompanied by reduction in the environmental impact per unit of electricity produced.

To convert these technological possibilities into realities will require truly major research and development outlays on the part of the government as well as the power industry. Substantial outlays will also be required to bring about needed environmental improvements in existing power technology, a notable example being the need to find practical ways of removing sulfur from the combustion gases discharged by coal-burning power plants, or from coal before it is burned.

In the area of transmission technology, achievement of economically practical undergrounding of high voltage lines, and further advances in extra-high-voltage ac and dc techniques for long-distance bulk transmission applications hold promise for efficiency gains and major environmental benefits.

Additionally, a great deal of further research will need to be done on the environment itself to reinforce present knowledge of the nature and extent of the effects and biological consequences of industrial operations on air and water quality and to build a new base for environmental standards and planning of protective measures.

The opportunities and needs touched on briefly here make it imperative that the power industry's present level of expenditure on research and development be substantially increased, and that appropriate regulatory policies

and mechanisms be established to facilitate and encourage this new scale of effort.

Financial imperatives: The continued growth and modernization of power systems to meet their public service obligations is wholly dependent on electric utilities being able to raise the capital required for these purposes. In the case of the investor-owned segment of the utility industry, which presently supplies approximately 77 percent of the nation's total electricity needs, capital requirements are met in part by reinvesting earnings, in part by sale of common and preferred stock (equity financing), and in part by borrowing money, mainly through the sale of bonds (debt financing). Reliance on debt financing has steadily increased and today it is the industry's major financing mechanism. The ease or difficulty of obtaining debt financing and the cost of that financing (e.g., the interest rate paid on bonded debt) depend on general conditions in the financing market and on the credit rating of the particular utility.

In recent years electric utilities have had unusually heavy financing requirements. In 1968 and 1969, for example, the power industry accounted for 18 percent of all U.S. corporate bond financing. These large financing requirements are a major reflection of the swollen dimensions of current utility expansion activities. The swelling has been caused by a number of factors, notably the heavy commitments the industry has made for nuclear plants, which have lower operating costs but require a larger capital investment than conventional thermal plants, and severe construction cost escalation, the effects of which have been compounded by delayed schedules and increased investment in environmental protection features.

These unusually heavy financing requirements developed at a time when capital was in unusually short supply and interest rates reached unusually high levels. As a result, the fixed charges on utility investment in new plants have risen substantially in a short space of time. As matters stand today, recoupment of such increased capital costs must usually await the presentation of definitive evidence that these costs are depressing utility earnings below a reasonable level. The same applies, with some exceptions (such as fuel adjustment clauses), to obtaining relief for increasing operating expenses. That the adverse cost factors mentioned are indeed having a depressing effect on utility earnings is evidenced by the fact that, after a long period of stable or declining electric rates, utilities across the country have been applying to their public service commissions for rate increases, most of which have been granted in whole or in part. The statistical average of investor-owned utility financial performance, as measured by the rate of return achieved on common stock equity investment, has been on a gradual downward trend since 1967. There have, of course, been individual exceptions to this general rule.

This is another example of the impact that changing circumstances have on electric industry operations. If allowed to continue, a downward trend in utility financial performance would create increasing difficulties for utilities both in attracting equity investment and in raising debt capital—and this at a time when their capital requirements promise to be larger than ever before. It is imperative, therefore, that procedures for making rate policies and rate adjustments be systematically reviewed, especially with a view to eliminating avoidable time lags, and that any inequities therein be promptly corrected.

A related regulatory imperative, already stated but worth repeating, is to insure policies and mechanisms necessary to enable and encourage a substantially higher level of utility research and development expenditure.

Nearly everything that has been said under this and all of the preceding headings points to the likelihood of higher electricity prices. Even with the best government stewardship, the best industry management, the most enlightened public attitudes, and continued excellent technological progress, it is to be expected that the current trend of upward rate adjustments will continue for at least several more years, partly because of the momentum of the underlying economic forces and partly because of changing social values which, among other effects, are causing our society to move in the direction of reckoning the full and true environmental "overhead" cost associated with a given product and including that cost in the price charged for the product. Disappointing technological progress could lead to even more substantial rate increases. Equally serious would be failure to allow proper transition time for bridging the gap between current performance and future

power objectives related to the new social values. The final imperatives, therefore, are for the nation to condition itself to regard electricity as a more highly valued commodity and for all concerned with power matters to recognize that their best efforts will be required to keep rate increases and industry performance in reasonable bounds in the years ahead.

In sum, the electric power industry, though diverse in character, is unique in that it is the nation's largest industry and provides essentially one single standard product—electric power on instant demand—which is essential to the continuing effective operation and orderly growth of the nation. The past performance, present capabilities for public service, and resilience of the nation's electric power supply system provide substantial hope that the enormous demands and critical conditions (including conservation of resources and protection of environmental values) can be met by a still better industry of the future. But none of these underlying factors can be taken for granted. They require vigorous and coordinated attention to insure that it is the public's true overall interest and not one segment of it that is served.

Summary of Survey Findings

Introduction

Two comprehensive surveys of the electric power field have been undertaken in recent years—the National Power Survey of 1964, which was completed in October 1964 and this National Power Survey of 1970. Many of the problems that face the industry and the nation today stem from changes that took place, or from pressures that began to build up, during the brief time interval between these two studies. Comparisons between the two survey reports bring differences between 1964 and 1970–71 conditions into sharp focus; accordingly, in summarizing the findings of the 1970 Survey we shall recall, where appropriate, the way things stood in 1964.

While each of the following twenty chapters of this report deals with a specific power topic, we shall in this chapter summarize the Survey findings under six broad headings: the structure of the power industry; the demand outlook; the relationship between electric power and environmental quality; research and development needs; and the price outlook. This form provides a more unified and understandable picture of the complex power field. For the reader's convenience, each of the six summary headings carries a footnote identifying the chapter or chapters in which the details of the subject matter are to be found.

Structure of the Power Industry [4]

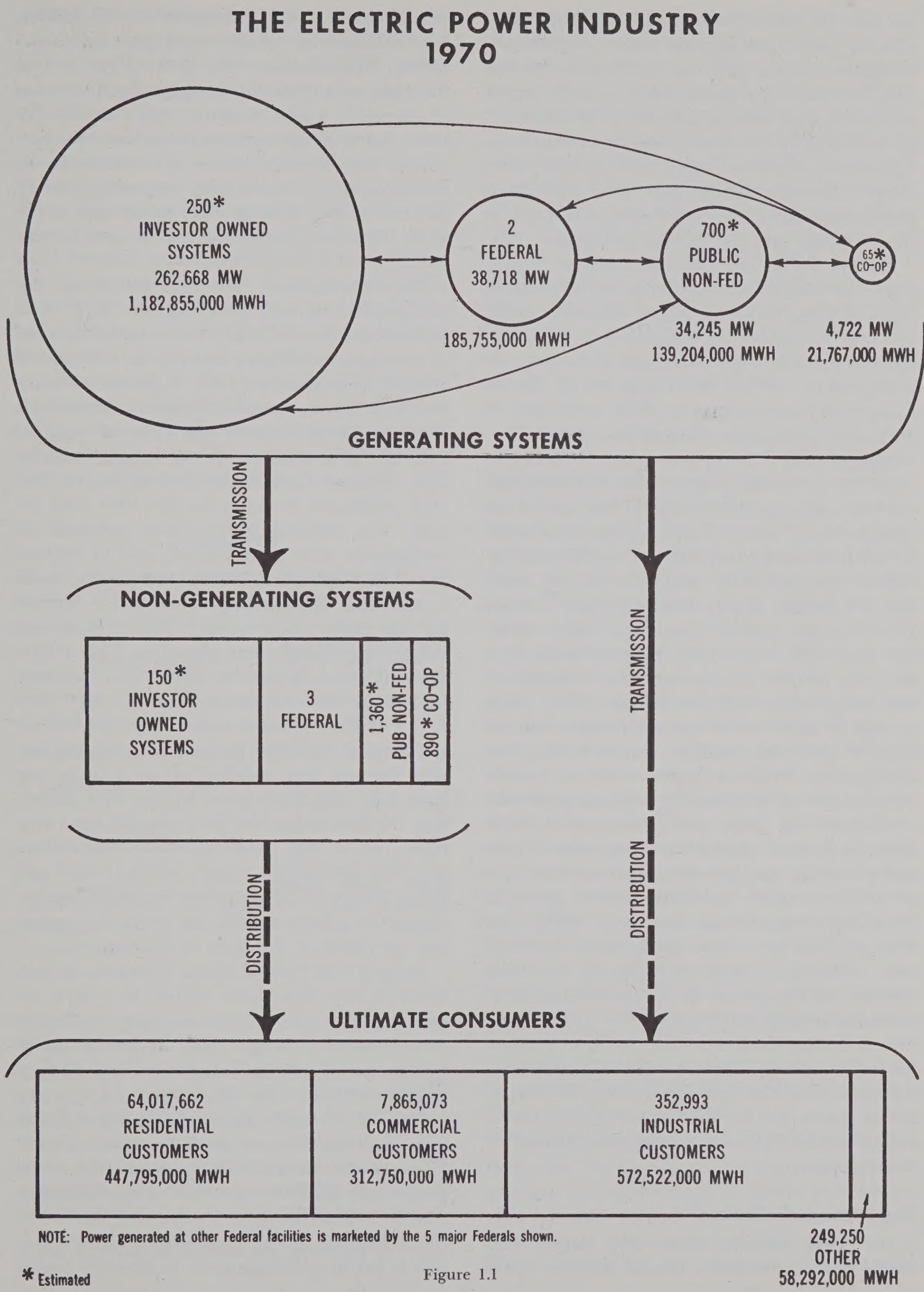
General The electric power industry is made up of a multiplicity of utility systems, some owned by private companies (investor-owned utilities), some owned by the federal government or by other public bodies such as municipalities, states or public utility districts, and some owned by electric cooperatives (see Figure 1.1). In all there are some 3,500 individual enterprises. As in some other industries, however, much of the total volume is handled by a small fraction of the total number.

The investor-owned segment is by far the largest, accounting for 77 percent of the nation's total generating capacity and 78 percent of the ultimate customers served as of December 31, 1970. Nearly all of the approximately 200 major investor-owned utilities operate integrated generation, transmission and distribution systems and some (so-called "combination companies") are additionally engaged in the distribution of gas within their service areas. There is about an equal number of smaller investor-owned utilities, most of which are engaged solely in electricity distribution.

The federally-owned segment of the power industry accounts for 11.5 percent of the nation's total generating capacity. It comprises some 40 systems which in the main supply power in bulk for local distribution and resale by others. With one exception (the Tennessee Valley Authority) the major systems are operated by agencies of the Department of Interior.

Utility systems owned by public bodies other than the federal government or by the consumers they serve account for 10.5 percent of the nation's generating capacity. This segment of the

[4] See chapter 2 for details.


THE ELECTRIC POWER INDUSTRY
1970
250*
INVESTOR OWNED
SYSTEMS
262.668 MW
1,182,855,000 MWH
2
FEDERAL
38,718 MW
185,755,000 MWH
700*
PUBLIC
NON-FED
34,245 MW
139,204,000 MWH
65*
CO-OP
4,722 MW
21,767,000 MWH
GENERATING SYSTEMS
TRANSMISSION
NON-GENERATING SYSTEMS
150*
INVESTOR
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SYSTEMS
3
FEDERAL
1,360*
PUB NON-FED
890* CO-OP
TRANSMISSION
DISTRIBUTION
DISTRIBUTION
ULTIMATE CONSUMERS
64,017,662
RESIDENTIAL
CUSTOMERS
447,795,000 MWH
7,865,073
COMMERCIAL
CUSTOMERS
312,750,000 MWH
352,993
INDUSTRIAL
CUSTOMERS
572,522,000 MWH
NOTE: Power generated at other Federal facilities is marketed by the 5 major Federals shown.
249,250
OTHER
58,292,000 MWH
* Estimated

Figure 1.1

industry is quite diverse in its make-up. Of a total of some 2100 separate systems, about two-thirds are solely engaged in the distribution and resale of electricity purchased from bulk power suppliers. Many municipally-owned utilities fall in this category, as do most of the rural electric cooperatives. The other one-third operate generating facilities, either as part of an integrated generation-transmission-distribution system or to supply power for distribution by others.

About 1,000 electric cooperatives supply power in many of the rural areas of the country. Most of these cooperatives are relatively small, and over 90 percent are engaged only in the distribution of electricity. Although these cooperatives account for less than 2 percent of the nation's generating capacity, they serve over 8 percent of the ultimate customers.

Observations There is a trend toward consolidation of utility systems but it is a very gradual one and at present is mainly confined to the investor-owned sector or involves the acquisition by investor-owned utilities of small publicly-owned systems. The existence of so many separate systems and, relatedly, the fact that the great majority operate on a small scale, has created and will continue to create difficulties. For one, the smaller systems are disadvantaged by not being able individually to build large enough installations to take advantage of economies of scale. For another, pluralism of utility management within a region tends to complicate the job of coordinating regional power development. For these and other reasons, some industry leaders advocate welding together the nation's utility enterprises to form a dozen or so centrally managed combines. Others view this approach as impractical because of the diverse and complex nature of the interests involved and advocate, instead, strengthened coordination of utility planning. The Federal Power Commission believes there is merit in the position that the industry can solve its most pressing "multiplicity" problems by pooling and coordination and believes that, given time, pooling of system needs and coordination of planning will create natural paths for needed consolidation of management.

The Demand Outlook

The 1964 outlook The 1964 Survey estimated that the nation's annual electric power requirements, which amounted to 1.0 trillion kilowatt-hours in 1963, would increase to 2.8 trillion kilowatt-hours by 1980. Other related forecasts were that the per capita consumption of electricity would nearly double over this period, and that the fraction of the nation's total energy consumption used to generate electricity would go up by nearly half, increasing from 21 percent of the total in 1962 to 31 percent in 1980. The 1964 Survey did not project beyond 1980.

The 1970 outlook The 1964 Survey (p. 39) projected a national peak demand in 1970 of 270,100 megawatts which was remarkably close to the experienced peak demand for that year of 276,000 megawatts. In 1966, in preparation for the 1970 Survey, Regional Advisory Committees were appointed to study the demand trend in each of the nation's six Power Supply Regions. The Advisory Committees, assisted by the FPC staff, developed forecasts for the 1970–1990 period. The regional studies were published in preliminary form as completed, and in September 1969 the Federal Power Commission issued a statement summarizing the resulting forecast for the nation as a whole.[5] The 1980 electric energy requirement was placed at 3.07 trillion kilowatt-hours, 14 percent higher than had been forecast by the 1964 Survey, and the 1990 level at 5.8 trillion kilowatt-hours. The upward adjustment of the 1980 forecast reflected the fact that demand was building up at a faster rate than had been anticipated by the 1964 Survey, and the belief that the 1970's would see a continuation of this trend. It should be stressed that this comparison is on a national basis and hence is only broadly descriptive. Details on the change in growth outlook for particular regions will be found in the body of this report.

Recently the Federal Power Commission instituted a new procedure calling for yearly regional assessments by the industry of the demand outlook ten years into the future. In the spring of 1971, the total of the regional forecast figures showed a further increase in the projected 1980 demand from 554,000 megawatts to 598,000 megawatts of capacity, plus reserves. Since it was impractical to update the entire body of the 1970 Survey and since the differences do not materially affect the picture the Survey

[5] These projections are included in chapter 3 and in parts II and III of this report.

presents, the decision was made to retain the demand projections developed in the 1966–1969 studies as the statistical base for the 1970 Survey report and all subsequent references to industry growth are keyed thereto.

Major demand components It may seem paradoxical that at a time when many individuals are calling for curtailment of power growth in the interests of environmental protection, the best judgment of those whose business it is to study demand trends is that the nation's electrical requirements will very nearly quadruple between 1970 and 1990, and that by 1990 electricity will have increased its share of total energy consumption to about 41 percent.

Before getting at the reasons for this outlook, it is helpful to divide the use of electricity in the U.S. into its major component parts and examine their relative importance. The perspective this provides is as follows:

TABLE 1.1

Categories of Electric Power Use 1965–1970–1990

Category of Use	Percent of Total Use		
	1965 [1]	1970 [2]	1990 [3]
1. Industrial	41%	40%	41%
2. Residential	24%	25%	24%
3. Commercial	18%	18%	20%
Sub-total	83%	83%	85%
4. Miscellaneous, including losses	17%	17%	15%
Total	100%	100%	100%

[1] Actual.
[2] Preliminary.
[3] Projections.

The first thing that stands out in this breakdown is that, apart from a modest but significant proportionate increase in commercial use, the basic use pattern over the next two decades is expected to remain about as it is today. This is another indication of the momentum of our society to which reference was made earlier in this chapter. The second thing that stands out is that it is the use of electricity in industry, rather than in the home, that constitutes the largest demand. A third significant point is that commercial use is not far behind residential use in demand importance. These considerations make it clear that even if the American people were willing to cut corners in their use of electricity in the home, which remains to be demonstrated, this of itself would not fundamentally alter the national demand outlook. Thus, with a residential use accounting for only one-quarter of total use, it would take a 10 percent reduction in *today's* household consumption to achieve a 2.5 percent reduction in *today's* total consumption. Moreover, many of the factors acting to increase the residential use of electricity (see below) would continue to be operative and so, even with corner-cutting, the net outlook would be for continued growth in household consumption, albeit at a somewhat reduced rate.

Discussion Those who are concerned about the environmental impact of electric power operations, and who would seek to curtail the growth of electrical demand on this account, sometimes lose sight of the fact that our society has an indoor as well as an outdoor environment and that the two are interdependent. We cannot expect to heat, light, refrigerate and power our indoor environment on a massive scale, as our society has become accustomed to doing, without affecting the outdoor environment. Conversely, restraints placed on allowable changes in outdoor conditions must sooner or later affect indoor standards. Clearly, what is needed is a balanced approach with all relevant factors properly weighted. Clearly, also, a situation of imbalance exists today in the nation's overall environmental ledger. Too much attention has been paid in the past to our indoor standard of living with too little heed to the side effects on the quality of the natural environment. Fortunately there is growing recognition that this problem exists and, as was mentioned earlier, a crusade to improve and protect the natural environment has gathered momentum. However all pendulums swing back as well as forth and so there is need to guard against the possibility of overcorrecting and thereby creating a new imbalance.

Electric power enters into the problem in two ways. On the one hand, the generation, transmission, and distribution of power have an impact on the natural environment in various ways and in varying degrees. We will speak to this topic later in this summary. On the other

hand, electricity itself ideally fills the indoor environmental need for a clean, versatile, and (as matters now stand) inexpensive form of energy. These three electrical characteristics explain why the residential and commercial demand for electricity has been growing, and promises to continue to grow, at a much faster rate than that for any other energy form. Cleanliness and flexibility are inherent characteristics unique to this refined form of energy; they will not change and so there is no need to discuss them further here. The inexpensiveness of electricity, on the other hand, is not an inherent quality of this form of energy and, further, is a relative matter. As was stressed in the assessment portion of this chapter and as will be elaborated upon later, the era of stable or gradually declining electricity rates appears to have ended. It is therefore important to examine the effect this trend reversal might have on future demand. Relatedly, some have proposed that changes be made in existing utility pricing policy as a means of moderating demand growth. These proposals, which range from eliminating price discounts to large-scale users to charging premium rates for large-scale use or for electricity supplied during peak demand periods, raise the same basic question of the relationship between price and use.

Insofar as residential demand is concerned at present price levels, most household uses of electricity are considered to be relatively price-inelastic (i.e., insensitive to price changes) and, within reasonable limits, rate increases would not be expected to have marked impact on demand growth. An important exception is space heating, a field of application in which electricity competes directly with other energy forms. The general turbulence of today's fuels market makes predictions risky but present indications are that considering convenience, cost trends, fuel availability, and environmental factors, electricity will continue its rapid gains in space heating and, accordingly, that the number of "all-electric" households will increase significantly. Since the all-electric household consumes nearly three times as much electricity as today's average household, this has important implications for the residential demand outlook.

In general, the same characterization holds true of the commercial demand for electricity and for the same reasons.

In the area of industrial use, although the availability of dependable low-cost electricity is a factor almost always taken into account in the selection of new plant sites, there are only a few industries in which the cost of electricity accounts for a substantial part of the cost of manufacture. With these exceptions, of which primary aluminium production is perhaps the outstanding example, the industrial use of electricity tends—again with limits—to be price inelastic. It is expected that increased emphasis on improving labor productivity and quality control standards will lead many industries to broaden, rather than contract, their uses of electricity and that a similar broadening of electricity usage will stem from steps taken in the interest of environmental protection.

The foregoing all relates to 1970–1990 demand growth in terms of annual kilowatt-hour requirements. Another aspect of demand growth covered by the 1970 Survey is that of load forecasting and, in particular, the forecasting of peak loads. One of the conclusions reached is that there is need for the industry to improve the accuracy of its present load forecasting methods. This need takes on particular importance in light of the lengthening lead times for major system expansion projects.

The Supply Outlook [6]

The situation in 1964 At the end of 1963 the utility industry had an installed generating capacity of 211,000 megawatts and during that year the industry's reserve margin—i.e., the amount of installed capacity in excess of peak load requirements—averaged 25 percent. With advances in system interconnection it was believed that lower reserve margins would suffice in the future. The 1964 Survey Report targeted a margin of 15 percent for 1980 and estimated that trimming the nation's reserve capacity to this level would reduce plant investment requirements over the 1964–1980 period by $5 billion. On this basis, the generating capacity needed to meet the projected 1980 peak load was placed at 527,000 megawatts, which meant that more than 300,000 megawatts of new capacity would need to be installed over the 1964–1980 period. Although this was obviously a massive undertaking, it was merely an extension of

[6] See chapters 4, 5, 6, 7, 8, 12, 14, 15, and 18 for details.

the industry's historic growth pattern and therefore tended to be viewed as a job the industry would take in its stride.

Four-fifths of the electricity generated in the United States in 1963 was produced from energy supplied by fossil fuel. With limited potential remaining for hydroelectric power development, the outlook was for progressively greater dependence on thermal power. Coal was by far the major fuel, accounting for 67 percent of that year's thermal power output. Next came natural gas (26%) and residual fuel oil (7%). The contribution of nuclear power was as yet nominal (less than 0.1%). Thanks to improvements in mine productivity and to reductions in transportation costs, the delivered cost of coal had been lowered substantially in the years leading up to the 1964 Survey, and this trend was expected to continue. Largely for this reason and notwithstanding a sharp upward trend in natural gas prices, the 1964 Survey projected that the *average* delivered cost of fossil fuel to utilities, measured in constant dollars, would decline. As this projection implied, the fuel availability outlook—with the exception of natural gas—was excellent.

As of 1964, slight improvements were continuing to be made in the thermal efficiency or "heat rate," of fossil-fueled generating plants but the point of diminishing returns had about been reached in conventional steam plant design. Moreover, many of the most modern units —i.e., those operating with the most advanced steam conditions—were experiencing above-average forced outage rates. For these reasons, the principal opportunity for continued cost reduction lay in building larger, more dollar-efficient, plants (economy of scale); and progressive increases in unit sizes were therefore anticipated.

Nuclear power stood on the threshold of large-scale commercial application in 1964 and was expected to become a major factor in the nation's power economy in the years immediately thereafter. Although less than 1000 megawatts of nuclear capacity were then in operation in the United States, the 1964 Survey forecast that there would be some 70,000 megawatts in routine service by 1980, amounting to 13 percent of the total generating capacity projected for that point in time.

Changes in conditions We have dwelt at some length on the 1964 situation since without this perspective it would be difficult for the reader to grasp how markedly supply conditions have changed since then. Before describing today's outlook, we will take brief note of some of the major intervening developments.

In November 1965, major sections of the northeast were blacked out by a massive power failure that started in Canada and spread in cascade fashion through interconnected American systems as far south as New Jersey. This was not the first failure of a power supply system, nor has it been the last, but it was by far the most extensive and dramatic and served to bring system reliability questions into much sharper focus than had previously been the case. Moreover, it taught a valuable lesson, which is that an industry responsible for so basic a service as the supply of electricity must guard against even highly unlikely eventualities. The investigatory studies and engineering reappraisals[7] that followed the blackout produced a number of positive results. Deficiencies in power supply systems, such as the lack of standby generators in some airports and hospitals, were uncovered and are being corrected. Regional reliability councils were established by the utility industry to coordinate the actions necessary to strengthen the reliability of interconnected systems. Out of the work of these councils has come a rededication to the principle of system interconnection. Previously, as the 1964 Survey reflected, the chief driving force behind the movement toward system interconnection was the economic benefit to be derived from sharing large power installations, exchanging power during non-coincident demand peaks, and the like. The searching reexamination that followed the Northeast blackout led to the conclusion that an even greater benefit of system interconnection is that, when properly conceived and executed, it can contribute importantly to the reliability of power supply. Thus, today, it is reliability more than economy that provides the thrust for the continuing drive toward more complete and better utility interties.

The first two nuclear power projects to be undertaken by U.S. utilities on a straight commercial basis were contracted for nearly a year before the 1964 Survey was completed; however,

[7] Prevention of Power Failures, Federal Power Commission, July 1967.

with a single exception, no further orders were placed until the late summer of 1965, nearly a year after the Survey Report was issued. Orders then began to be placed with some frequency and by the summer of 1966 it was evident that nuclear power was making a market breakthrough of landslide proportions. By late 1967, the U.S. Atomic Energy Commission was forecasting that between 125,000 and 170,000 megawatts of nuclear capacity would be in service by the end of 1980. The AEC's "most probable" figure (147,000 megawatts) was essentially double most prior estimates. Never before in the United States or elsewere had an industry undertaken to introduce a major new technology on such a massive scale.

Because of its massive dimensions, the industry's construction program would have been a formidable undertaking even under ideal conditions. As rapidly became clear, however, conditions in the latter 1960s were far from ideal. The nation's manufacturing capabilities were being taxed by the demands of a boom economy, and the strain reflected itself in late equipment deliveries and lower quality. Costs were generally inflated, and with investment capital under heavy demand and in short supply, interest rates rose to exceptionally high levels. There was unprecedented escalation of construction wages, the effects of which were compounded by unsettled labor conditions and by a serious decline in labor productivity. These adverse factors, over which the power industry had little or no control, acted to delay many power projects and substantially increased their cost. They had particularly severe impact on nuclear projects, which involve a larger capital investment than conventional thermal power plants and entail more field construction labor. Moreover, many nuclear projects encountered special problems, such as intervention in licensing proceedings by opposition groups, other licensing delays, and changes in licensing criteria requiring costly design modifications. To these were added the normal difficulties associated with the large-scale introduction of a major new technology. Finally, utilities found that building progressively larger generating units, either fossil or nuclear, presented new difficulties at both the plant construction and start-up stage. In the meantime, as was brought out earlier, the demand for electricity was building up in some areas at a faster rate than had been anticipated. The net result of all of this, aside from severe cost effects to be discussed later, was a dramatic change in the nation's power supply situation. Utility reserve margins rapidly eroded, in some cases to the point where emergency measures were required at peak load periods. In the late 1960s, the average reserve margin fell from the 1963 level of 25 percent above the summer peak load to less than 20 percent and in some areas the reserve was much below this average. Almost overnight —or so it seems in retrospect—a few sections of the nation were confronted with the prospect, if not the fact, of serious power shortages.

Still another major development in the latter 1960s was an abrupt change in the short-term fossil-fuel supply outlook. Here there were two major factors. First, utility demand for coal expanded at a more rapid rate than the coal industry's production capability and for this and other reasons a generally tight coal situation quickly developed. Second and even more important in its immediate effects, the widespread enactment of environmental protection regulations limiting the allowable sulfur content of fuel burned in thermal power plants, both here and abroad, created a large demand for low-sulfur coal and oil in some areas which quickly strained the available supplies. As a consequence, fossil fuel costs, which had been trending downward, made a sharp reversal and began to rise rapidly. In some instances fuel costs literally doubled. Moreover, in several areas utilities were faced with the prospect of serious fuel shortages. During the latter half of 1970 a combination of these problems and others which included rail shipping difficulties and heavy exports of coal led to dangerously low coal stocks at many electric power plants, particularly in the Southeast region. Some utilities which normally maintain a two-month supply were down to a two-week supply or less.

The 1970 Survey Findings

Capacity In arriving at estimates of future capacity requirements, the 1970 Survey concluded that with varying regional patterns industry planning should overall be based on

maintaining[8] an average reserve margin of approximately 20 percent, rather than on trimming the margin to 15 percent as had seemed possible at the time of the 1964 survey. This conclusion was reached in light of the industry's increasing dependence on large generating units and the consequent need for large blocks of reserve capacity to offset unscheduled outages. Relatedly, the larger, more complex facilities, on which the economics of modern power generation so importantly depend, have tended to date to have higher-than-average forced outage rates and/or to require longer-than-average maintenance shutdowns. Whether this will continue to be the case cannot be predicted with any degree of certainty. There is as yet too little experience, especially with large nuclear units, to say whether large unit size inherently means some degree of reduced reliability. What is certain is that unit sizes are increasing rapidly and will continue to increase. Up until 1960, when the first 450-megawatt unit was placed in service, the nation's largest generating units had a capacity of 335 megawatts. In 1970 a substantial fraction of the new base-load capacity placed in service consisted of units of 500 megawatts or larger. Many units 1,000 megawatts and larger, including nuclear units, are now under construction and unit sizes may reach the order of 2000 megawatts by 1980 and possibly 2700 megawatts by 1990.

With a 20 percent reserve margin, the electrical demand projections stated earlier[9] translate to the following requirements for total installed generating capacity:

Year	Net Generating Capacity Required at Year's End
1980	665,000 megawatts
1990	1,260,000 megawatts

At the end of 1970 the nation had an installed generating capacity of approximately 340,000 megawatts. These requirements thus mean that the industry will need to make net additions of some 325,000 megawatts of generating capacity during the 1970's and 595,000 megawatts during the 1980's. In effect, the industry's present plant will need to be almost quadrupled during the next two decades.

[8] The word "maintaining" should perhaps be clarified. The actual national summer peak load margin has been below the 20 percent level for the past several years, but is expected to regain that level upon completion of current construction projects. Some regions have recently been operating with reserve margins as low as 13 or 14 percent.

[9] Reference here is to the projections developed by the Regional Advisory Committees in the 1966–1969 period, which form the statistical basis for the 1970 Survey. As was noted in the text, more recent studies of 1980 loads indicate somewhat greater demand growth.

TABLE 1.2

Projected Growth of Utility Generating Capacity[1]

(all figures in thousands of megawatts)

Type of Plant	Class of Service (see text): *Base Load*	*Intermediate*	*Peaking*	Installed Capacity End 1970	1970–1980: Projected Additions	1970–1980: Projected Retirements	1970–1980: Projected Installed Capacity End 1980	1980–1990: Projected Additions	1980–1990: Projected Retirements	1980–1990: Projected Installed Capacity End 1990
Hydroelectric										
Conventional	seasonal			52	16		68	14		82
Pumped storage			√	4	23		27	44		71
Thermal										
Steam-electric										
Fossil-fuel-fired	√ (newer units)	√ (older units)		260	157	(24)[2]	393	225	(61)[2]	557
Nuclear	√			6	141		147	353		500
Gas-turbine & diesel			√	19	12		31	20		51
Totals (rounded)				340	349	(24)	665	656	(61)	1260

[1] Keyed to electrical demand projections made by Regional Advisory Committee studies carried out in the 1966–1969 period. Premised on average gross reserve margin of 20%.

[2] Units placed in service prior to 1955.

TABLE 1.3

Distribution of Generating Capacity

[Based on Table 1.2 projections]

Type	Percent of Total Capacity [1]				
	In Service End 1970	1970–1980		1980–1990	
		Additions During Period	In Service End 1980	Additions During Period	In Service 1990
Hydraulic					
Hydroelectric	15	5	10	2	7
Pumped storage	1	7	4	7	6
Sub-totals (rounded)	16%	11%	14%	9%	12%
Thermal					
Steam-electric					
Fossil-fuel-fired	77	45	59	34	44
Nuclear	2	40	22	53	40
Gas turbine & diesel	6	3	5	3	4
Sub-totals (rounded)	84%	89%	86%	91%	88%
Total	100%	100%	100%	100%	100%

[1] Since different types of plant are operated at different capacity factors, this capacity breakdown is not directly representative of share of kilowatt-hour production. For example, since nuclear plants are customarily used in base-load service and therefore operate at comparatively high capacity factors, nuclear power's contribution to total electricity production would be higher than its capacity share (see table 1.4).

The capacity growth projections are given in somewhat more detail in tables 1.2 and 1.3. The first of these exhibits lists the projected capacity additions for the 1970–1980 and 1980–1990 periods by type of plant; the second shows the percentage breakdown for each period and cumulatively. The salient features of this forecast are summarized below:

1. Base-load service: Base-load plants—i.e., those designed to run more or less continuously near full load, except for periodic maintenance shutdowns—are the "workhorses" of the power generating industry and typically produce 60 to 80 percent of their rated maximum output during any given year. They are highly engineered to produce electricity as efficiently and cheaply as possible consistent with high reliability standards. As table 1.3 reflects, the nation is already heavily dependent on thermal (as distinct from hydroelectric) power installations for base-load service and the base-load capacity additions projected for the next two decades are predominantly thermal. The reason is that most of the nation's favorable hydroelectric potential is already being used, leaving fuel as the chief energy source on which the power industry can draw. As between fossil fuel and nuclear fuel, the outlook is for progressively heavier reliance on the latter. Although nuclear plants accounted for only about 2 percent of the nation's 1970 thermal base-load capacity, they are expected to account for approximately 50 percent of new thermal base-load capacity additions during the 1970's and for nearly 70 percent during the 1980's.
2. Peak load service: Peak load units are designed to supply electricity principally during times of maximum system demand and characteristically run only a few hours a day. They are engineered to facilitate quick start-up and shut-down and with a view toward minimizing the capital investment, rather than the en-

ergy production cost. As table 1.3 reflects, gas turbines and diesel generators are commonly used for peak load service today. However, over the next two decades, and except in those utility systems which do not have suitable sites, pumped storage units are expected to overtake them in importance. Pumped storage operates on the principle that during off-peak hours, excess thermal capacity is used to generate electricity to pump water from a river or other source up to an elevated reservoir. Then, during the hours of peak demand, the flow of water is reversed and used to generate power hydroelectrically to help meet the peak load. There is a net loss of energy in the process; as a rule of thumb, for every three kilowatt-hours of electricity fed into pumped storage, only two are returned. However, the overall economics are such that where suitable sites exist, pumped storage usually offers the cheapest and most dependable source of power for peak requirements.

3. Intermediate service: Between the base-load and peak-load extremes lies the intermediate duty cycle. The plants used for intermediate service operate at capacity factors in the range of 20 to 60 percent and must be able to respond readily to swings in system demand. In general, the smaller, older fossil-fuel-fired units, originally built for base-load duty, are used for such service. Increasingly, however, cycling steam units are being built specifically for intermediate service, and large diesels and some gas turbines also fit such use.
4. General: A striking fact about the outlook reflected in tables 1.2 and 1.3 is that of the total amount of base-load capacity projected to be in use by the end of 1990, about 83 percent will be of post-1970 vintage and more than half of the total will be less than ten years old at that point in time.

Commonly two or more generating units are built on a single site and the resulting complex is referred to as a power plant or power station. Many existing thermal stations have sufficient land and cooling water available to accommodate the installation of at least one additional generating unit. However, it is certain that meeting the projected expansion requirements while retiring older generating stations located in congested urban areas will require finding sites with suitable environmental characteristics for a large number of new power stations. (See later discussion.)

Fuel supplies As fundamental to the supply of electricity as the adequacy of generating plant capacity is the adequacy of the energy sources on which the plants depend. In the nation's predominantly thermal power economy, the central question is whether fuel supplies will be available in the vast quantities that will be required.

Four basic fuels are used in thermal power generation, the three fossil fuels—coal, natural gas and oil [10]—and uranium, today the basic fuel of nuclear power. Table 1.4 shows the relative importance of each in 1970 and projections for 1980 and 1990. The forecast is keyed to the plant capacity projections already discussed, taking into account the expected mode of operation of the several types of plant involved (base load, intermediate load or peaking service). Coal supplied 54 percent of the energy used in

TABLE 1.4

Projected Distribution of Fuel Use for Thermal Power Generation 1970–1990

[Percent of Heat Input][1]

Fuel	Year		
	1970	1980	1990
Coal	54%	41%	30%
Natural gas	29%	14%	8%
Residual fuel oil	15%	14%	9%
Nuclear	2%	31%	53%
Totals	100%	100%	100%

[1] Staff Estimates. The projected uses of each of these fuels in 1980 and 1990 are based on assumed prices and availabilities. If the assumptions vary, then the mix of the fuels actually used may also vary.

[10] Most of the fuel burned in power stations is "residual," i.e., the heavy fraction remaining after petroleum has been distilled to produce gasoline and other light or intermediate hydrocarbons.

thermal power generation in 1970; however, with nuclear power coming into the ascendancy, coal's share of the utility fuel market is expected to drop substantially, falling to 30 percent by 1990. Natural gas supplied 29 percent of the 1970 total, but its share is expected to diminish to 8 percent by 1990. Residual fuel oil's share is expected to decline from 15 percent in 1970 to 9 percent by 1990. Nuclear fuel on the other hand is expected to increase its proportional share by many-fold from about 2 percent to 53 percent. Geothermal energy amounts to a very minor percentage of total usage presently, but is receiving increased attention in certain areas of the country.

In absolute terms, the 1970 Survey's fuel requirement projections are as shown in table 1.5. As is apparent, the projected growth in energy consumption for electric power generation is such that, despite their declining share of the utility-energy market, all three fossil fuels will be in increasing demand over the next two decades. Specifically, utility consumption of coal is expected essentially to double, and consumption of natural gas is expected to increase by less than 20 percent. Nuclear fuel requirements will, of course, grow dramatically over the same period. Meeting these utility requirements will pose difficult problems, which will take different forms for each fuel.

The nation's aggregate resources of coal are vast. However, coal is not uniform, varying greatly in physical and chemical properties, and in costs to mine and transport. The bulk of the low sulfur and inexpensive coals which are found in the West are located far from utility demand centers, which are predominantly in the East. Coals nearer to load centers are generally rather high in sulfur, or are expensive to mine. Utilities are finding it increasingly difficult, if not impossible, to locate deposits that are large enough and can be mined and transported at a reasonable cost to supply the requirements of a large power station, and that have a low enough sulfur content to meet the increasingly stringent limits of environmental regulations. Coal prices for some plants have doubled between 1969 and 1971.

With large-scale low-sulfur coal supplies remote from centers of need and unsuited for use in existing boilers, many utilities will be required to install equipment to remove sulfur from furnace gases before discharging them from the power plant stack. Stack gas sulfur removal processes have been under development for a number of years and some are being demonstrated, but not yet satisfactorily at a commercial scale. Removal of organically bound sulfur in mined coal requires full chemical processing. Thus, present indications are that limitations on sulfur dioxide emissions drastically increase production costs in coal-burning power plants.

Other factors that cloud the utility coal cost outlook include tightening mine safety standards, which will act to increase the cost of coal production in underground mines, and tightening environmental regulations, which will increase the cost of and sometimes prevent strip mining. In short, doubling the output of utility coal over the next two decades poses a difficult challenge for the coal industry and almost certainly will entail significant cost increases, either at the mine, in shipment, or at the power plant.

In the case of natural gas, with the supply sit-

TABLE 1.5

Projected Annual Fuel Requirements for Thermal Power Generation

Fuel	Year 1970	1980	1990
Coal	322 million tons	500 million tons	700 million tons
Natural gas	3,600 billion cubic feet	3,800 billion cubic feet	4,200 billion cubic feet
Residual fuel oil	331 million barrels	640 million barrels	800 million barrels
Uranium ore*			
without plutonium recycle	7,500 tons	41,000 tons	127,000 tons
with plutonium recycle	7,500 tons	38,000 tons	108,000 tons

*Short tons of U_3O_8 required to supply feed for diffusion plants to supply annual burnup and new reactor inventories.

uation already tightened, with wholesale prices rising, and with some evidences of gas commanding higher prices in intra-state than in inter-state markets, those utilities which have traditionally depended on this energy form—principally southwestern and west-coast systems—are uncertain about future gas availability and price levels. The expectation is that natural gas supplies will at best be marginal during the 1970s and may become inadequate during the 1980s unless new domestic or foreign supplies are successfully developed, or unless techniques are found for producing gas from coal (so-called coal gasification) on a commercial basis.

Utility supplies of residual fuel oil, and especially of oil of low-sulfur content, are largely obtained from foreign sources since the economics of U.S. petroleum refining presently do not favor the production of this fuel form. Continued heavy reliance on foreign sources appears likely; and with world requirements for oil continuing to increase rapidly, more constrained supply situations could well develop in the coming decades.

In the case of uranium, the nation's and the world's resources are potentially vast—many times larger than those of fossil fuels—but realization of more than a small fraction of their potential awaits successful development and use of breeder reactors. Breeder systems are under intensive development in the United States and several other countries with the objective of introducing full-scale breeder plants on utility systems during the 1980s. Such plants, however, are not expected to account for a major portion of the total nuclear power capacity until the 1990s (see later discussion under Research and Development). In the meantime many utilities will be making extensive use of power reactors that extract only a percent or two of the energy content of uranium and whose favorable economics depend on the availability of comparatively low-cost uranium supplies (relative to the supplies it will be possible to draw upon once breeder reactors are in use). The nation's present proven reserves and stockpiles (as distinct from estimated resources) of low-cost uranium, which are largely a heritage of exploration programs carried out during the mid-1950's in connection with defense requirements, are more than adequate to meet the power industry's projected needs over the next decade. With the resumption, several years ago, of large-scale exploration efforts, substantial new deposits are beginning to be located. Thus, with major new discoveries reported abroad, the outlook is for adequate ore sources so long as adequate exploration efforts are sustained and provided that the development of breeder reactors does not encounter serious delays. Major build-up of the nation's uranium mining and milling capacities will be required, necessitating significant capital investment. Accordingly, uranium prices, which of late have been depressed, are expected to find higher levels as the projected nuclear power build-up takes place.

Transmission Transmission is steadily growing in importance to electric supply, as more generation sites are located distant from the load centers and more interconnections between systems are used to enhance reliability and economy. With this growth there has been a continuing increase in the capacity of individual lines by use of higher voltages, and in a few instances, by use of direct current systems. In urban areas particularly, the difficulty of obtaining overhead rights-of-way is causing greater consideration to be given to placing new transmission lines underground.

It is believed that these established trends will continue through the next two decades, assisted by technical advancements. Prior to 1969 the highest transmission voltage in the United States was 500 kilovolts; in the fall of that year the first 765 kilovolt transmission facility was placed in service and by 1980 some 3,500 circuit miles of 765 kilovolt transmission may be in use.

Transmission trends and projections are closely related to the growth of system interconnections and the reliability of the national electric power network. Chapters 17 and 18 discuss these factors in detail.

Reliability Making power available whenever needed and minimizing service interruptions have been major objectives of the electric power industry throughout its history. However, the rapidly increasing loads and attendant expansion of transmission networks throughout most of the nation, coupled with the extensive Northeast power failure of November 1965, have focused new attention on the reliability of interconnected systems. In July 1967, the Federal Power Commission published a three volume report "Prevention of Power Failures," which rec-

ommended as a key step in bulk power supply reliability the establishment of regional joint planning and operation of electric power facilities.

In response to the evident need the industry has greatly expanded its coordination arrangements. By the end of 1970, 21 contractual agreement power pools were in operation, representing some 60 percent of installed capacity, as compared to only 9 pools in 1960. In addition, there are at least thirteen informal organizations of utilities in the contiguous United States which engage in more limited aspects of intersystem coordination. Beginning in 1967 the utilities established a number of regional electric reliability councils and in 1969 formed the National Electric Reliability Council (NERC) to encourage improvement of coordination at both the regional and national levels. At the end of 1970 the nine regional councils included virtually all major electric utilities in the 48 contiguous states, comprising about 90 percent of the total installed capacity. Provision is made for participation by the smaller utilities. Chapter 17 discusses industry coordination arrangements.

It is expected that the varied industry-wide efforts to consolidate and expand utility groupings will continue and that centralized pool-wide dispatch will attain increased acceptance as the need grows for more sophisticated control of separate, interconnected control areas. Stronger interconnections between regions, beyond those presently planned by the utilities, appear desirable.

The Relationship Between Power and The Environment [11]

The 1964 outlook In 1964, apart from traditional conservationist interest in land use and the beginnings of concern by ecologists about other fundamental environmental questions, concern over the environmental effects of electric power operations was largely confined to the electric utilities themselves and to those agencies of government involved directly or indirectly with the power industry. The 1964 Survey Report contained an extensive discussion of the effects of power operations on air and water quality. It anticipated that these effects might present difficulties as the scale of power operations increased, and called for increased industry emphasis on pollution controls and for research in this general field of power technology, especially in the area of ecological studies. While it cited the possibility that added costs of environmental protection might prevent full realization of the targeted reduction in the average cost of electricity, it concluded that "the nation's capacity to produce needed electrical energy will not be impaired because of these environmental considerations."

1970 Survey findings As was brought out in Part A, public interest in environmental questions has awakened since 1964 and there is today what amounts to a national crusade to improve environmental quality. As stated in the Introduction of the report [12] to the Commission by the National Power Survey Task Force on Environment:

> "In our time, we have seen commanding new social values arise, and among the most important of these is a new respect for the conservation of the environment, and the need to adapt our energy sources and supply to the restrictions this imposes upon us."

As already observed, the problem our society now faces is how to protect and, where possible, to upgrade the quality of the outdoor environment without cancelling out the gains that have been made in the quality of our indoor environment and, equally important, without denying these same gains to new generations or to those among us who have not yet shared them but seek to do so.

While electric power is almost ideal insofar as the indoor environment is concerned, its production and supply may, and usually does, have undesirable effects on the outdoor environment. The areas of effect can be categorized as follows:

1. Effects on air quality stemming from discharge into the atmosphere of combustion products from fossil-fuel fired power plants or from the release of trace amounts of radioactivity from nuclear plants;
2. Effects on water quality stemming from

[11] See chapters 10, 11, and 12 for details.

[12] "Managing Power Supply and the Environment," July 1971.

the discharge of waste heat from thermal power plants; the discharge of some chemicals into the waterways serving the power installations; and the discharge of trace amounts of radioactivity from nuclear plants;

3. Land-use effects, including ecological effects of hydroelectric power operations; accumulation of solid waste (fly ash) from coal-fired power plants; the commitment of substantial tracts of land for power plant sites or for transmission rights-of-way; and commitment of substantial physical areas for long-term storage of radioactive wastes from nuclear power plants.
4. General esthetic effects (noise, appearance, and the like).

The 1970 findings on each of these areas of effect will be briefly summarized in the order listed.

Air quality (fossil fuels): Large fossil-fuel fired power plants produce tons of waste combustion products daily. In varying degree the different kinds and grades of fossil fuels present problems of soot control, ash disposal, and gas emission—in particular, sulfur dioxide, nitrogen oxides and carbon monoxide. Natural gas is the cleanest of the three fuels in most of these respects, and coal, especially coal of low heat value or high sulfur content, is the most troublesome. The following data are indicative of the amounts of major pollutants emitted by electric power plants in comparison with other major sources:

TABLE 1.6

Estimated Nationwide Discharges of Airborne Pollutants—1968

[Million tons per year]

	Carbon Monoxide	Particulate Matter	Sulfur Oxides	Hydro-Carbons	Nitrogen Oxides	Total
Power Plants	0.1	5.6	16.8	Neg.	4.0	26.5
Other fuel combustion in stationary sources	1.8	3.3	7.6	0.7	6.0	19.4
Transportation	63.8	1.2	0.8	16.6	8.1	90.5
Industrial processes	9.7	7.5	7.3	4.6	0.2	29.3
Solid waste disposal	7.8	1.1	0.1	1.6	0.6	11.2
Miscellaneous	16.9	9.6	0.6	8.5	1.7	37.3
Total	100.0	28.3	33.2	32.0	20.6	214.2

Note: Sulfur oxides expressed as tons of sulfur dioxide and nitrogen oxides as tons of nitrogen dioxide.

Source: National Air Pollution Control Administration (now Air Pollution Control Office, Environmental Protection Agency).

As these figures reflect, apart from sulfur dioxide emission to which electric power operations are the major contributors, the electric power industry is far from being the major source of air pollutants. It is nonetheless a significant source and, moreover, it is a concentrated source. And in view of the overall seriousness of the nation's air pollution problems, especially in or near major urban and industry centers, there is obvious need to do all that is within technology's power to reduce the emission of any and all significant air pollutants, from whatever source, to the lowest levels possible.

Recent federal and state legislation, culminating in the Clean Air Quality Act Amendments of 1970, has greatly strengthened regulatory powers over air pollution and, among other provisions, has mandated the establishment, by 1971, of national air ambient quality standards. Under this mandate individual states must present implementation plans designed to control emissions from stationary and other emission sources in such a manner that the ambient air quality standards will be met by 1975. Electric utilities, working closely with their equipment suppliers and with their architect engineers,

have already taken a number of major steps to minimize the emission of air pollutants from existing as well as future generating installations, and additional steps are in view. The steps already taken include the development of greatly improved particulate systems incorporating mechanical devices as well as ultra-high-performance electrostatic precipitators; discharge of the scrubbed gases through high stacks at high velocity so that they enter the upper atmosphere and thereby have minimal local effect; the maximum possible use, subject to supply limitations, of fuels of low sulfur content; substantial reductions in nitrogen oxide formation through modified combustion techniques and flue gas recirculation; and the rapid and massive introduction of nuclear power into base load generating practice (see below).

Of the additional steps being taken by the industry, a key one in the near-term electrical supply outlook is the accelerated development of equipment to remove sulfur from the combustion gases before they are discharged from the plant stack. The bulk of the coal burned by U.S. utilities has had a sulfur content in the range of 2 to 4 percent by weight. Increasingly, utilities are being required by local environmental protection statutes to burn fuel having a sulfur content of 1 percent or less, and in some instances the allowable limit has been set below 0.5 percent. The available supplies of coal or other fossil fuels as low as 1 percent, much less 0.5 percent, are very limited in relation to the massive needs of the power industry. Thus, unless practical sulfur-removal systems can be quickly developed and put to use, the fossil fuel supply outlook will be very bleak indeed and those areas that have established especially low sulfur restrictions may either have to relax them or face the prospect of power shortages.

A number of different sulfur removal processes have been studied and several have been piloted in small or medium-sized installations. However present indications are that it will be several years before full-scale systems are ready for routine commercial service. Amplifying a point made earlier in this chapter, the basic technical feasibility of sulfur removal is not in question; what remains to be done is to refine the engineering design of the several competing systems, to demonstrate that full scale installations can be made to perform reliably in routine plant service, to reduce their projected high capital and operating costs, and to provide for disposition of the resulting products.

Air quality (nuclear fuels): Nuclear power plants produce no bulk waste products. They do create radioactive substances which, although small in terms of physical mass, are large in terms of contained radioactivity. These are chiefly the "ashes" of the fission process (fission products), which form within the fuel material and all but a tiny fraction of which normally remain locked inside the sealed fuel assemblies. This material is removed periodically from the plant when spent fuel assemblies are taken out of the reactor, loaded into shielded containers, and shipped away for reprocessing. The comparatively few fission products that escape from the fuel assemblies, together with short-lived radioactive substances formed outside the fuel (activation products), are routinely removed by purification equipment, securely packaged and shipped away for burial at federally controlled sites. Only trace amounts are released to the plant environs.

The release of radioactivity from nuclear power plants is restricted by regulations of the U.S. Atomic Energy Commission, which has statutory responsibility for the licensing of all nuclear power activities.

Since December 1970, responsibility for setting the radiation standards has been vested in the Environmental Protection Agency, which to date has made no change in the limits previously established by the Federal Radiation Council.

In its development of regulations to implement the radiation standards, the AEC has consistently sought to keep radioactivity releases from nuclear power plants not merely within the limits allowed by the standards but as low as practicable. In mid-1970, the AEC proposed an amendment to its regulations to limit nuclear plant radiocativity releases to 1 percent of the exposure established by the Federal radiation protection guides for the general public. This action reflects two important nuclear power trends: first, the actual experience with radioactivity releases from nuclear power plants has been excellent; second, recent advances in reactor system design will enable future nuclear power plants to do an even better job of radioactivity confinement.

Water quality: The electric power industry relies heavily on the nation's water resources. It uses but does not consume approximately four-fifths of the total water used by all industry for cooling purposes. It also accounts for nearly one-third of the total water uses for all purposes. The power industry's use of water (as coolant but not for consumption) is expected to increase substantially along with the nearly quadrupled scale-up of power generation in the next two decades.

The principal ways in which electric power operations can affect water quality are through the discharge, from thermal power installations, of heat, chemicals and, in the case of nuclear installations, trace amounts of radioactivity. Additionally, there is the possibility of effect through sheer physical displacement—i.e., water flow. Of these possible sources of effect, heat is the most significant and has attracted the greatest amount of attention from conservationists, ecologists and the public. Therefore we will speak first, and mainly, to this topic.

It is a basic law of thermodynamics that whenever heat energy is converted to another form, there is a net loss that becomes "waste heat." In modern fossil-fuel-fired power plants, up to 40 percent of the heat released in the boiler is converted into electrical energy. The unused heat energy is discharged to the plant's environs, about 90 percent of it going into the water that is used for condenser cooling and the balance being carried into the atmosphere by the stack gases. Today's nuclear plants operate at lower thermal conversion efficiencies (around 31%) and thus discharge more waste heat per kilowatt-hour of electrical output. Since there is no loss through a stack from a combustion process, essentially all the waste heat from a nuclear plant goes into the turbine condenser cooling water.

Most often the condenser cooling water has been handled on a "once-through" basis; in other words it is drawn from a body of water such as a river, pumped through the condenser and then discharged directly back to its source. Large flows of water are involved—about 1,500 cfs [13] in a modern 1000 megawatt fossil-fueled plant. Typically, the discharge stream is from 10° to 30°F warmer than the inlet stream. However, as the warmed water rejoins and mixes with the receiving body of water, the temperature difference quickly reduces and, depending on local conditions, is often undetectable a few hundred yards from the discharge point.

There is a valid concern that the local temperature differences and their effect on the oxygen content of the water and on other conditions important to the aquatic eco-system, together with the sheer movement of so much water, may upset the natural balance of aquatic life. Research is under way by both utilities and government agencies to understand thermal effects and to establish criteria for warm water discharges from power plants. The indications to date from this research are that, *when properly controlled,* warm-water discharge from power plants has had little, if any, adverse effect on water quality and, indeed, in some localities is considered beneficial to fish life. In isolated cases fishkills have resulted from fish being trapped against the intake screen or being attracted to the warm water at the discharge point and then being caught by changing conditions. Such problems have been solved or show promise of solution by engineering modifications with guidance of fishery biologists. Concern persists, however, and until a very great deal of additional investigatory work has been done, and until enough has been learned to enable scientists to correlate and generalize upon results obtained under a wide variety of conditions, conclusive answers will be lacking.

Government agencies have responded to public concern by establishing or proposing strict regulations governing warm-water discharge. The landmark step was the enactment of the Water Quality Act of 1965. In 1968, comprehensive Water Quality Criteria were issued by the Federal Water Quality Administration, then a branch of the Department of Interior and subsequently incorporated into the Environmental Protection Agency (EPA). In most states no thermal power plant can be built until the responsible regulatory agency is satisfied that applicable water quality standards will be met.

Alternatives to the direct discharge of heat to natural bodies of water (once through cooling) include man-made cooling ponds or lakes and cooling towers, which may be either "wet," rejecting heat to the atmosphere by water evaporation, or "dry" where heat is transferred by

[13] cubic feet per second.

conduction as in the automobile radiator. All involve considerable added cost and large structures as compared to once-through cooling.

However, as a result of the increasing difficulty in finding sites where power plant waste heat can be acceptably discharged to natural bodies of water, utility plans for new generation facilities are increasingly based on the use of cooling ponds and cooling towers. The Commission staff believes that the trend will continue and that by 1980 the great majority of new generation facilities, except for those on the coasts, will employ some form of closed cycle cooling system. If the standards are found to be overly stringent, the nation's electricity consumers will be carrying an unnecessary and increasing cost burden, perhaps to the detriment of other more critical environmental needs.

Since the nation's water resources are complex (consisting of oceans, lakes, rivers, streams, estuaries, surface reservoirs and underground water tables, which have relationships one to another) and since the nation uses these resources in multiple and often interrelated ways, it is necessary to take a "systems" view of water quality problems. At the same time, the broad scope and complexity of the subject mandates a case-by-case approach to the problem of setting standards. This involves studying a particular water or body or stream system to establish its basic ecological characteristics and to assess how these characteristics might be affected in the short and long term by current and projected future uses.

Neither cooling ponds nor cooling towers are completely free of environmental effects (in esthetics, use of sizeable acreage, and local atmospheric effects). For example, the plume of water vapor given off by wet cooling towers can cause local fogging under certain climatic conditions, especially in northern latitudes. Also, there are difficulties in applying either method in coastal installations where saline water is used for condenser cooling.

Of less significance to water quality control than the thermal discharges from power operations, but not inconsequential, are the discharge of chemicals. In the case of nuclear plants, the release of trace amounts of radioactivity must also be considered. The chemicals involved are mainly those used to control fouling, algae growth, and the like in the tubing of the turbine condensers through which the cooling water flows. This practice needs careful study to distinguish its biological effects from those attributable discretely to thermal discharges as the increasing scale of power operations makes both important factors in the future. Accordingly, many of the newer power plants are being designed to employ mechanical tube cleaning devices which will substantially reduce the need for chemicals.

Much of what was said earlier about the air quality aspects of the controlled release of radioactivity from nuclear plants applies as well to the release of radioactive substances into water bodies. Here, as in airborne releases, the industry's experience record has been excellent. Releases have been kept within a very small fraction of the limits set by radiation protection standards. Here, however, there is a special consideration that has given some ecologists cause for concern—namely, the possibility that some aquatic organisms might concentrate radioactivity from some compounds they uptake. This radioactivity might then find its way into the human food chain. (The same possibility of course also exists with airborne releases but to a much lesser degree.) Concentration phenomena have been taken into account in the development of the radiation protection regulations that govern the releases but in this area of environmental effect, there is need for continued research and for continuing monitoring programs to ensure that if concentration effects occur they will be detected and corrective actions taken.

Land use: In the aggregate, the electrical power industry uses large amounts of land, comprising principally generating sites and transmission rights-of-way. A large generating station requires a site of at least several hundred acres, and EHV transmission right-of-way requires some 20 or more acres per mile of line. In the past it was the industry's practice to locate generating stations in or near load centers, which usually meant placing them in or close to densely populated areas. With the growth of system inter-connection, and more recently with the advent of mine-mouth coal-fired plants and remotely-sited nuclear plants, many generating facilities have been located at considerable distances from load centers. This practice has tended to reduce land use conflicts at the load center but often has increased the difficulty of securing the transmission right-of-way in the

rural areas. Moreover, the construction of generating plants in "unspoiled country" is often challenged on conservation grounds and there have been similar challenges to the construction of the necessary transmission connections.

The projected quadrupling of the scale of electric power operations over the next two decades, bring with it attendant requirements for the development of some 300 major new thermal generating plant sites and the construction of some 90,000 miles of additional 230 kilovolt and higher voltage transmission line. While the selection and qualification of these sites (many in relatively remote locations) presents a formidable task, this picture is counter balanced considerably by a substantial number of sites already evaluated, and by the fact that in this period many less usable existing sites will be abandoned, reducing urban area impact in many cases. The situation nevertheless, speaks for advanced land use planning for many different communities and land interests.

The growth in all sectors of the country, with the attendant demands for land, is emphasizing the increasing burden of separate rights-of-way for highways, railways and transmission lines. Many believe that combined rights-of-way can provide advantages to the public in some cases, and believe that serious consideration of the possibilities should be undertaken. Looking into the future, two of the imperatives stressed in Part A will contribute to satisfactorily resolved land use questions, improved siting procedures and better technology to counter possible detrimental environmental effects.

Esthetics: Over the years the electric power industry has contributed its share to the industrial "uglification" of the nation's landscape through the construction of many badly functional generating plants and unsightly transmission and distribution lines and also through the noise and intrusion of bulk coal transport and handling operations. So long as there was little or no public concern over appearances, the industry doubtless felt, and with considerable justification, that its public-service responsibilities —in particular the obligation to provide power at the lowest possible cost consistent with high dependability standards—dictated a Spartan approach to esthetic matters. Today, the public mood is different and in recent years the power industry has paid increasing attention to esthetic values. The steps it has taken include close attention to the architectural treatment and landscaping of its newer generating plants and distribution sub-stations; the development of more pleasing transmission tower designs; and the undergrounding, where practicable, of distribution lines. The industry has been aided in the first-mentioned of these efforts by the advent of nuclear power. Nuclear plants are inherently clean in design and since they do not require bulk fuel handling facilities or extremely tall stacks, they lend themselves well to modern architectural treatment and park-like settings.

While the industry has made and continues to make good progress in improving appearances, much remains to be done. Ways must somehow be found to replace many existing overhead distribution lines with underground installations and a great deal of work needs to be done to develop reliable, economic techniques for the undergrounding of high-voltage transmission lines.

General: On balance, and with the exception of esthetic factors, concern about the impact of electric power on the quality of the outdoor environment stems more from consideration of the industry's future growth requirements than from its effects to date. Relatedly, this discussion would be incomplete without reference to an environmental control procedure that has recently been instituted which provides the nation with a major line of defense against unwarranted future environmental impact. This procedure stems from a requirement of the National Environmental Policy Act of 1969 that each federal agency, when authorizing any major undertaking which might significantly affect the environment, prepare, release publicly and circulate to interested federal and state level agencies a report assessing the expected environmental impact and evaluating all practical alternative courses of action. Under the procedure established by the President's Council on Environmental Quality to implement this statutory requirement, the agency primarily concerned must first circulate a draft report or comparable information. Later after detailed comments have been received, a final report is prepared. These reports are regularly received and reviewed by the Council on Environmental Quality and the Environmental Protection Agency.

The potential value of this procedure as an environmental control can perhaps best be conveyed by listing the basic subject areas these environmental reports are required to cover. They are as follows:

1. The environmental impact of the proposed action;
2. Any adverse environmental effects which cannot be avoided should the proposal be implemented;
3. Alternatives to the proposed action;
4. The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity;
5. Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

Research and Development Needs [14]

General As was stressed in Part A of this chapter, solutions to many of the major problems the nation faces in the electric power field hinge on technological progress, and technological progress, in turn, hinges on research and development. A number of specific areas of power technology in which there is both need and opportunity for major advances have already been cited. The need to fill the broad gaps which presently exist in our knowledge of the environmental effects of power operations has also been cited. These major research and development needs, together with others not yet mentioned, are listed in table 1.7 under four broad categories: generation technology, transmission technology, distribution technology, and environmental sciences.

Several of the needs listed in table 1.7 will require research and development efforts of enormous scope and complexity and hence will necessitate large financial outlays over an extended period. A case in point is the need, recently highlighted by President Nixon in his June 4, 1971 message to the Congress on the nation's energy outlook, for the expeditious development of breeder reactors for use in central station nuclear power plants. Achievement of this objective will bring at least three major benefits:

1. First, by creating more fissionable material than they consume, breeders will conserve nuclear fuel, substantially extend nuclear fuel resources and significantly reduce fuel cycle costs.
2. Second, the successful development of breeders will create a premium market for the byproduct plutonium produced by nonbreeders and thereby benefit the operating economy of existing types of nuclear power plants.
3. Third, breeders are high-temperature systems and thus will achieve high efficiency in converting heat to electricity. As a result, power plants employing breeders will discharge substantially less waste heat to the environment per kilowatt hour of electrical output than the types of nuclear power plants now in commercial service.

The Atomic Energy Commission and the utilities have already spent hundreds of millions of dollars on breeder reactor development. The work has now advanced to the stage where plans are being developed for the construction of a commercial size demonstration breeder power plant to help prepare the way for introducing this technology into regular power practice in the early 1980's. The power industry's share of the cost of this demonstration project, exclusive of the book value of the capital investment in the plant proper, is estimated at $150 to $250 million, and could well run higher. The total research and development costs in advancing breeder technology to the stage of full-scale commercial application are expected to approach $2 billion.

Another illustration of the potential magnitude of the financial outlays the industry may be called upon to make for research and development in the next two decades is provided by the item listed on table 1.7 as "research on controlled fusion." The successful development of techniques for inducing nuclear fusion reactions under controlled conditions and of practical fusion reactors for power generation would give mankind the key to virtually inexhaustible energy resources and could pay other important environmental dividends. Work toward this "ultimate solution" to the world's electricity needs

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[14] See chapter 20 for details.

is presently at the basic research stage. Although significant progress has been reported recently, none of the laboratories engaged in this research has yet succeeded in demonstrating controlled fusion. Once this has been done, the next major step will be to prove that fusion reactions can be carried out in such a manner as to achieve a net energy gain. Beyond that lies the giant step of demonstrating the economic feasibility of large-scale fusion installations. Until the basic technical feasibility questions have been answered it will be impossible to make any meaningful estimate of the magnitude of the research and development problems entailed. If, however, the nation's and the world's experience in developing fission reactors is any indicator, the chances are that the job of developing fusion reactors will require tens of thousands of man-years of scientific and engineering effort and several billion dollars of government and industry research and development expenditures.

In comparison with breeder reactor development and controlled fusion research, the other research and development needs listed on table 1.7 are modest in scope but by the standards of most industries each represents a sizable undertaking in its own right. In the 1970 Survey review of these needs, two principal conclusions emerged. First, it would be impractical for the electric power industry or the nation to attempt to pursue all of these major needs on an all-out basis. Moreover, such an effort would be completely disproportionate in light of other pressing national needs. Clearly, therefore, priorities must be assigned and the overall effort must be sensibly scaled in relation to research and development needs outside the field of electric power. At the same time—and this is the 1970 Survey's second principal conclusion on this subject—it is equally clear that the present pace of research and development in this field is inadequate to the nation's needs and therefore the level of support must be substantially increased both by the industry itself and by those agencies of government active in the field.

For the past decade electric utilities have been supporting research and development at a level estimated to be equivalent to approximately one quarter of one percent of gross electrical revenues. The industry's gross electrical revenues are currently of the order of $20 billion per year, and the annual rate of clearly identified utility research-and-development expenditure in 1969 was in the neighborhood of $40 million. An additional amount of about $110 million was spent by utility equipment manufacturers. The estimate for utilities would be substantially higher if one were to include the "incremental" costs the industry has incurred in building and operating pioneer nuclear power stations—i.e., the costs incurred over and above the norm of the industry's experience with conventional power installations of comparable size. There is no question but that a substantially higher rate of utility expenditure will be required to ensure a rate of technological progress commensurate with the industry's needs, and that government support levels will also have to be stepped up. The allocation of effort as between the industry and the government (both at the federal and state levels) is, of course, a key consideration. Studies of this and other research and development policy questions are currently being conducted under the aegis of the Electric Research Council with the participation of all segments of the electric power industry. These studies indicate that utility expenditures, exclusive of funds devoted to breeder reactor demonstration, should be raised in the near term to an annual level of $150–200 million. This would represent a three to four-fold increase in the scale of utility-sponsored research and development and raises important organizational and financing questions. Further increases should be contemplated and encouraged by regulatory authorities as the revamped program and organization take hold.

Organizational mechanisms The past decade has seen a trend toward deeper utility involvement in the research and development process. Over much of its history the utility industry delegated much of the responsibility for technological progress to its equipment suppliers and paid the cost indirectly—i.e., through the purchase of equipment priced to provide for recovery of the manufacturers' research and development expense. This pattern began to change with the advent of nuclear power, the pioneering of which required a scale of industry expenditure that mandated direct utility participation, in some cases by individual utilities but more commonly by groups of utilities working as teams. Also, since nuclear power represented a fundamentally new technology and showed

TABLE 1.7

Major Research and Development Needs in the Field of Electric Power

Category	Item	Reliability and Safety	Cost Reduction	Conservation of Fuel Resources	Air Quality	Water Quality	Esthetic Values
		Major Areas of Benefit					
A. Generation Technology	1. Reduction of sulfur emission from fossil-fuel-fired plants through the development of equipment for the removal of sulfur dioxide from combustion gases and of techniques for the removal of sulfur from coal before it is burned.				√		
	2. Reduction of nitrogen oxides emissions from fossil-fuel-fired plants through closer control of combustion conditions.				√		
	3. Reduction of particulate emission from fossil-fuel-fired plants through the continued refinement of electrostatic precipitators and other stack gas scrubbing equipment and techniques.				√		
	4. Reduction of radioactivity releases from nuclear plants through continued refinement of plant and equipment design and operating techniques.				√	√	
	5. Reduction of warm-water discharge from thermal power plants in general through advances in the design and use of cooling ponds and towers and also through the development of new generating technologies (see below).					√	
	6. Minimization of the effect of warm-water discharge through the development of improved cooling water intake and discharge structures and operating techniques.					√	
	7. Continued scale-up of the size of generating units through advances in equipment and plant design.		√				
	8. Improvement in plant dependability through the development and use of more rigorous quality control techniques and procedures, the gathering and analysis of equipment reliability statistics, more sophisticated maintenance programming and the like.	√	√				
	9. Development of new techniques, such as magnetohydrodynamics (MHD), which will make it possible to achieve higher thermal conversion efficiencies and reduce waste heat rejection.			√	√	√	
	10. Continued nuclear power safety research including study of accident mechanisms and testing of engineered safeguards.	√					
	11. Expeditious development of breeder reactors for use in nuclear power plants.		√	√		√	
	12. Continued research on fuel cells			√	√	√	
	13. Research on controlled fusion		√	√			
	14. Investigation of the possibilities of new approaches to tapping solar energy.			√	√	√	

TABLE 1.7—Continued

Category	Item	Major Areas of Benefit: Reliability and Safety	Cost Reduction	Conservation of Fuel Resources	Air Quality	Water Quality	Esthetic Values
B. Transmission Technology	1. Improvements in equipment reliability through advances in materials technology and engineering design, and the establishment of needed testing facilities.	√					
	2. Continued improvement in the esthetics of transmission tower design.						√
	3. Continued advances in extra-high voltage (EHV) transmission (from 500 kw to 765 kw and above).		√				
	4. Continued development of new transmission techniques, such as the use of superconducting cryogenic cable and DC transmission methods.		√				
	5. Development of reliable, economic methods for undergrounding high-voltage transmission line.	√					√
C. Distribution Technology	1. Improvement in undergrounding of distribution lines.						√
	2. Improvement in the automation of distribution facilities.		√				
D. Environmental Sciences	1. Continued study and monitoring of individual ecosystems—e.g., a particular lake or estuary.					√	
	2. Development of improved techniques and devices for tracing the path of effluents from power operations, including constituents of stack gases from fossil-fuel-fired plants and radioactivity releases from nuclear plants.				√		
	3. Continued study of the short and long-term biological effects of subtle changes in environmental conditions resulting from power operations.	√			√	√	
	4. Establishment of data gathering and analysis centers and technical information dissemination services in specialized areas of the environmental effects field.				√	√	
	5. Continued research in the environmental "ologies" (seismology, meteorology, geology, hydrology, etc.).	√			√	√	
	6. Development, through the application of the knowledge gained from the foregoing, of improved air and water quality standards and improved environmental protection criteria in general.				√	√	

promise of early commercial application, there was obvious need for interested utilities to participate intimately in the development work as a means of training key personnel and otherwise preparing themselves for the undertaking of commercial nuclear power projects.

More recently, the arousing of public interest in environmental quality has caused utilities to place substantially increased emphasis on ecological research, much of which is inherently local in focus and requires direct utility support and close utility participation. In these and other ways utilities have of late become progressively more involved in research and development, and all indications are that this trend will bring about major changes in the "structure" of this important field of activity.

With the possible exception of locally oriented ecological investigations, much of the industry's research and development needs cut across utility system lines and many of them are truly national in scope. This fact, plus the sheer magnitude of the effort that the industry will be required to support in the years ahead, argues for a coordinated approach to the planning, budgeting, and direction of most of its future research and development activity. As the industry now stands, however, its pluralistic and highly diverse nature presents impediments to effective coordination. Recognizing these facts, the industry through its present coordinating vehicle, the Electric Research Council, has been studying the establishment of a more comprehensive and effective industry-wide coordination mechanism. General agreement has been reached on two cardinal points: first, that the greatest part of the industry's research and development effort should be centrally directed and carried out in a coordinated manner and, second, that the entity established to provide this direction and ensure this coordination should be a non-profit organization representing all segments of the utility industry and administered by an industry-appointed board of directors. There also appears to be general agreement on the essential functions the coordinating organization would carry out, namely:

1. To serve as the channel through which at least the bulk of the industry's research and development funds would flow;
2. To budget and allocate these funds along lines approved by its board of directors;
3. To provide a continuing forum for the identification and assessment of the industry's research and development needs and priorities and for the formulation of guidelines for research and development undertakings;
4. Subject to board approval, to translate these priorities and guidelines into specific research and development programs, and to arrange for and administer their execution by qualified industrial organizations, research institutions and government laboratories and possibly in other facilities created for this purpose by the coordinating organization;
5. To develop and implement effective procedures for the appropriate dissemination of the results of the research and development activities under its jurisdiction.

While general industry agreement has been reached on the broad principles just described, there is as yet no industry consensus on the form the coordinating should take or on how it should be structured. There are at present two schools of thought on the matter. One is that advantage should be taken of the existence of the Electric Research Council, which, it is argued, has earned broad industry acceptance and provides an established framework within which the necessary coordinating machinery could, with some structural modifications and extensions, most readily and expeditiously be housed. The other school of thought is that a wholly new entity, amounting to an Electric Research Institute, should be created to carry out the vital and difficult task of research and development coordination. The difference between these two schools of thought is perhaps more philosophical then substantive. The ultimate choice between these and other possible alternatives, and the structural design of the entity decided upon, will doubtless be influenced by legal as well as policy considerations and also by financing considerations. In all of these areas many questions remain to be resolved. What is most important is that the industry resolve these questions with determination and dispatch so that it can proceed as promptly as possible to

implement the fundamental goals on which agreement has been won.

Financing mechanisms As has been brought out, the indications are that the utility industry will need to increase the proportion of the revenues it devotes to research and development three or four fold in the years immediately ahead. There is a growing feeling that the industry, composed as it is of diverse elements and a multiplicity of individual utility systems, has too unwieldy a structure to permit so substantial a scale-up of research and development effort to be achieved on a purely voluntary basis with utilities individually deciding the level of funding they will support. Some form of general prescription which, once decided upon, would be binding on the industry as a whole and more or less automatic in its application seems essential. Various prescriptions have been proposed, but upon close examination they reduce themselves to one or the other of the following two basic alternatives:

1. Enlist the broadest possible utility participation in a plan under which the utilities would pledge themselves to support a given level of research and development on a basis proportionate to their size as measured by their annual kilowatt-hour sales or other equitable size determinant. The funds they provide on this basis would be channeled in whole or in large part through a centralized coordinating organization as previously described. The participating utilities would enjoy free and equal access to the fruits of the collective research and development effort. (Non-participants would be required to pay fees or royalties for such access.) This approach presupposes that regulatory authorities would approve and accept the pledged utility expenditures as allowable expenses for rate-making purposes. Alternatively, with regulatory approval, the participating utilities might simply make an add-on charge for research and development and include it in the price of every kilowatt-hour of electricity sold as a kind of rate rider. With broad industry participation, an add-on charge of 0.1 mill per kilowatt-hour would be sufficient to achieve the general level of research and development presently believed to be required ($150–200 million per year, exclusive of the funds needed for breeder-reactor demonstration which would be raised on an ad hoc basis).
2. Raise the necessary research and development funds by levying a flat federal or state tax on all electricity sales. This tax revenue would then be made available to the industry, on an allocated basis, to enable it to meet its research and development responsibilities. Here, as above, the funds so allocated would be channeled in whole or large part through a centralized coordinating organization.

In principle, these two approaches would achieve essentially the same end. Whether this would prove to be the case in actual practice is debatable. Government, whether at the federal or state level, usually seeks to avoid pre-allocating specific tax revenues to specific expenditure needs since pre-allocation would deprive it of flexibility to adjust its expenditures to meet changing needs and changing circumstances. This consideration gives rise to the possibility that the tax-levy route might not assure the necessary momentum and continuity of industry research and development effort. There is also industry concern that this route might lead to an undue and undesirable degree of government control over the industry's research and development activities. The first of the above two alternatives appears to hold the greater promise.

The Price Outlook

The 1964 Survey outlook At the time of the 1964 Survey the price of electricity appeared to be following the same generally downward trend which had carried the average retail price for residential, commercial and industrial sales, expressed in current dollars, from 2.7 cents per kilowatt-hour in 1926 to 2.2 cents in 1940 and 1.7 cents in 1962. This long-term trend was in sharp contrast with almost every other price pattern in the American economy. For example, over the period 1940 to 1962, during which the average price of electricity—again on a current-dollar basis—was reduced by nearly 25 percent, the average price of consumer goods (consumer

price index) rose more than 200 percent. The electric power industry's remarkable price record, achieved in the face of rising costs of labor and materials and general inflation, was made possible by gains in efficiency and economies of scale. Through technological progress the industry was able to build progressively larger, more efficient installations in which, despite the adverse cost factors just mentioned, the investment required per kilowatt-hour of electrical output was steadily reduced. In effect, the power industry was capitalizing on its capital-intensive nature—i.e., on the fact that a high proportion of the cost of producing and supplying electricity is made up of the fixed charges on the plant investment (as distinct from the variable costs of plant operation, such as the cost of fuel). The industry was also capitalizing, of course, on the rapid growth in electrical demand and consequent periodic need for major additions to utility systems.

In 1964, the expectation was that the downward trend in electrical prices could be continued. The 1964 Survey Report proposed that the industry adopt the goal of reducing the average retail price, expressed in 1964 dollars, to 1.2 cents per kilowatt-hour by 1980, a level about 27 percent below that of 1962 on a constant-dollar basis. Closer coordination of utility planning and extension of system inter-ties were advocated to attain this goal, which the Survey estimated would reduce the nation's 1980 electrical bill by as much as $11 billion.

The 1970 Survey outlook The dramatic reversal which has recently occurred for the first time in more than 25 years the long-term decline in real kilowatt-hour costs is a key indicator of the major forces of change at work in the business of supplying electricity. As of now, the actual kilowatt-hour costs have decreased within the limits predicted in 1964. However, it has now become evident that several potent factors have reversed the trend and give strong indications of an upward thrust in the next two decades. From the best estimates derived today from the load-supply projections and base data of the Regional Advisory Committees, the Commission estimates that the average actual dollar costs of 1.54 cents per kilowatt-hour in 1968 will increase to approximately 1.83 cents per kilowatt-hour by 1990, measured in 1968 equivalent dollars, plus additions to reflect whatever inflation of the dollar is experienced up to 1990. While the use of 1968 dollars sets aside inflation factors the possible result to the consumer is reflected in varying assumptions of dollar inflation rates showing in table 1.8. Prominent among the influences causing this marked change in the historical cost trends are: added costs for environmental protection and enhancement features; sharply increasing competition for available fossil fuels; rising fixed charges for the increasingly capital-intensive industry—all of which are unlikely to be fully offset by the gains expected from economies of scale and new technology.

The distribution of the estimated 1990 costs (in 1968 base dollars, and possible 1990 current dollars) among power supply functions, as compared to the 1968 cost distribution, is shown in table 1.8.

The annual compound rate of increase experienced in the Consumer Price Index in the eight-year period beginning with 1962, averaged 3.0 percent per year. If this were chosen as the

TABLE 1.8

Cost of Electricity to Ultimate Consumers

[Cents per kilowatt-hour]

	1968 Actual Cost	% of Total	1990 Projected Cost			
			1968 Equivalent Dollars	With 1% Inflation	With 3% Inflation	With 5.7% Inflation
Production	0.77	50	1.09	1.36	2.10	3.18
Transmission	0.20	13	0.30	0.37	0.57	.89
Distribution	0.57	37	0.44	0.55	0.84	1.28
Total	1.54	100	1.83	2.28	3.51	5.35

projected inflation rate for the next twenty-two years, the average cost of electricity to consumers would rise to about 3.48¢ per kilowatt-hour in 1990, or more than double the current dollar costs in 1968. A partial reflection of the near-term effect of the cost increasing factors cited above is shown by the increase in average delivered cost per kilowatt-hour which rose from 1.54 cents in 1968 to 1.64 cents in 1970 in current dollars.

The cost of electric power production and delivery to consumers has three principal components: fixed charges on capital investment; fuel expenses, if applicable, and operating and maintenance expenses, excluding fuel but including allocated administrative and general expenses. The fixed charges are dependent, of course, on the amount of capital investment and the fixed charge rates related to that investment. Future projections of investment costs per kilowatt of new generating capacity necessarily entail a number of judgmental factors applied to a range of component elements. The detailed estimates contained in chapter 19 show nuclear plants averaging at least 25 percent higher in capital cost than fossil fuel plants of the same size. Regional differences within a range of about 10 percent are shown for fossil fuel plants with narrower variations for nuclear plants in various parts of the country. However, setting aside yearly inflation factors, for the analyses of the Survey report it is assumed that averaged over the next twenty years the capital investment levels per kilowatt of generation will be approximately as shown in table 19.3.

The estimates for high-voltage transmission costs over the next two decades must be conjectural because of pressures for development of practical and economical solutions for undergrounding at least some portions of these lines. Projected costs in the Survey include a 15 percent addition to the estimated total cost of an "all overhead" transmission system in 1990. This addition is to allow for placing a minor percentage of high-voltage transmission lines underground at high cost compared to overhead construction. Progress in undergrounding of distribution facilities as distinct from transmission facilities, is already well advanced and within the coming decade should be a conventional part of almost all systems.

An important new element in future financing requirements is the high initial investment required for fuel inventories for nuclear reactors. This investment, amounting to about $30 per kilowatt, is amortized as fixed charges, since nuclear cores last for substantial periods and are not fully consumed during cycling through the generating plant. The fuel burnup, however, becomes a part of fuel expense. The unique nature of nuclear fuel investment has led to recent endeavors to develop special financing arrangements to minimize this additional fixed capital burden on the utilities.

Because of the capital-intensive nature of the utility industry as already noted, the annual cost of this nuclear fuel inventory becomes a major factor in overall costs of power. In recent years the increasing capital demands of the utility industry have faced a competitive money market and interest rates near historic high levels. As a consequence, the Survey estimates that the composite average of fixed charges for the industry for steam generating plants with a thirty-year life would, in the next twenty years, be about 13.7 percent, as compared with approximately 11.2 percent in 1962. This estimated composite percentage reflects the whole range of types of thermal generation, in different regions of the country and facilities financed by a hypothetical entity representing the national mix of federal, municipal, cooperative and private ownerships.

Also significant in probable influence on power cost trends is the prospective increases in costs of fossil fuels on which an estimated 61.8 percent of power generation will depend in 1980 and 44.3 percent in 1990. Although early analyses postulated somewhat lower fossil fuel cost increases, it is the judgment of the Commission that fossil fuel "constant dollar" costs by 1990 are likely to increase by approximately 50 percent in the case of coal and oil and 100 percent in the case of natural gas. To these estimates must be added projected effects of dollar inflation to estimate the costs to consumers. Underlying these drastic increases are the factors already cited, including: increasing competition for available supplies, domestic and foreign; longer and more expensive transportation movements; upgrading of fuel quality; and environmental protection measures, including possible restrictions on strip mining of coal. It seems

unlikely that the total effect of all these influences can be counterbalanced by improved efficiencies in production and use of fuels and from economies of scale. However, one helpful factor in this picture is the indication that with the rapid growth expected in nuclear steam generation, its lower fuel burnup costs in 1990 (countered in part by higher capital costs) are estimated to average 0.16 cents/kwh in 1968 dollars compared to a cost of 0.38 cents/kwh for fossil fuel and an overall average fuel cost of 0.29 cents/kwh for all types of thermal generation. To this extent it can be said that further emphasis on resolving any technical and environmental problems of bringing nuclear power into fuller use can help materially in stabilizing the indicated general costs of power production.

The electric power industry is a living instrument of public service. To maintain and improve its healthy condition it is essential to understand the many characteristics of the industry as well as its problems and opportunities, which are examined in substantial detail in the National Power Survey. As the Survey indicates, one can anticipate processes of dynamic change as the industry adapts to a variety of new influences (technical and societal) both private and public in nature. But the processes of change need to be orderly and, to the greatest extent possible, balanced with thoughtful consideration for their consequences and distinctions between short and long-term significance. An institution so complex, so important in its daily readiness to serve, and so intricately involved in the fabric of the nation calls for the utmost skill in management and scrupulous balancing of the public interests.

CHAPTER 2

STRUCTURE OF THE ELECTRIC POWER INDUSTRY

The electric power industry in the contiguous United States includes nearly 3500 systems [1] which vary greatly in size, type of ownership, and range of functions. It is made up of four distinct ownership segments—investor-owned companies, non-Federal public agencies, cooperatives, and Federal agencies—and is unique among world systems in the diversity and complexity of its organization. Most systems serving large population centers are vertically integrated, i.e., they perform the functions of generation, transmission, and distribution. In contrast, there are many systems which provide distribution exclusively, and others that generate some power while relying on firm purchases to meet part of their requirements. These are mostly smaller systems and are largely in the municipal and cooperative segments. The extent to which the smaller generating systems can remain viable will depend in part on their obtaining additional supplies of power at costs which reflect the economies of large-scale generating plants now being constructed.

Historical Background of the Industry

From its small beginnings at Edison's steam-electric station in New York City, the electric industry has experienced rapid growth and development. The American response to the continuously expanding need for electric power has been reflected in an intermingled pattern of public and private ownership of power systems. In the early 1880's, local groups generally built electric power plants to provide energy either for incandescent lighting of small interiors or arc lighting of outdoor and large interior areas, both essentially night loads. The desire to utilize available generating capacity during daylight hours often lent impetus to the development of motor loads in industrial, commercial, and transportation ventures. Conversely, some electric systems initially established to supply street railways or interurban lines, or manufacturing or mining businesses, later expanded to carry the evening load of household and street lighting.

The need to use direct current at comparatively low voltages restricted the territory that could be served by the distribution network of any given electric power plant. Coupled with a limited demand for power, this resulted in the establishment of many small local companies. Frequently, two, three, or more noninterconnected plants, operating under different patents and owned by different concerns, were established in the same city.

Introduction of the transformer in 1886 led to the use of alternating current, higher distribution voltages, and an expansion of the distribution area that could be served by an individual plant. Improvements in generators made possible larger outputs at lower unit costs, while other technical improvements made it possible to supply incandescent and arc lights as well as direct and alternating current motor loads from the same power source. The increasing economies of scale in power production and the standardization of equipment led to many consolidations of the small electric companies serving given communities or areas. The diminution of competition resulting from these consolidations of power production plants and distribution systems was one of the factors leading to government regulation of public utilities. In a number of cases the local government acquired ownership of the electric system in an effort to provide electric power at lower rates for local consumers.

During the 1920's the holding company form of business organization gained popularity

[1] There were 3445 systems as of the end of 1968.

among investor-owned companies. In part this was because it accommodated expansion of system size; in part it was because it improved the ability of operating companies whose securities lacked investment stature to meet their growing needs for new capital. Holding companies provided investors with territorial diversification and an opportunity for earnings growth which was not always available in the common stock of the small, local firm.

Absorption of operating companies by large holding company systems became more widespread during the latter part of the 1920's. Even among holding companies, there were consolidations, reorganizations, and realignments of various sorts. As a consequence, the proportion of the industry's total capacity owned by independent operating companies was markedly reduced. By 1932, systems in eight large holding company groups generated about three-fourths of the output of all privately owned systems.

The depression period had a drastic impact on the utility holding companies and their operations. Electric generation fell 20 percent between 1929 and 1933. Because utility holding companies were financed in large part by debt obligations, a drop in the earnings of the operating companies had a magnified impact upon the earnings of the holding companies. In some cases, they were unable to meet fixed interest obligations to their bondholders, and bankruptcy and reorganization proceedings became necessary.

In an effort to correct the financial and accounting abuses that had occurred in some of the holding company operations, Congress passed the Public Utility Act of 1935. Title I of the Act authorized the Securities and Exchange Commission to simplify the corporate structures of the electric and gas industries, and thus facilitate state and Federal commission regulation of these companies. The Securities and Exchange Commission was also authorized to make studies and recommendations as to the type and size of geographically and economically integrated public utility systems, and was given certain regulatory authority with respect to public utility holding company systems. Title II authorized the Federal Power Commission to regulate wholesale electric rates in interstate commerce, to regulate some aspects of corporate management, finance and accounting, and to encourage interconnection and coordination. Although expressly recognizing that Federal regulation in these matters was necessary in the public interest, Congress carefully preserved the states' rights over intrastate matters.

Ownership and Structure

While the present patterns of electric power industry ownership and structure date from the 1930's, the composition of the industry is in a perpetual state of change, reflecting the interaction of technology, market growth, and institutional relationships. The historical and current ownership patterns in terms of numbers of systems are shown in table 2.1.

TABLE 2.1

Number of Electric Utility Systems by Ownership Classification

Ownership	1927	1937	1947	1957	1968
Investor-Owned	2,135	1,401	858	465	405
Public Non-Federal	2,198	1,878	2,107	1,890	2,075
REA Cooperatives		192	887	1,026	960
Federal [1]	1	3	4	5	5
Total	4,334	3,474	3,856	3,386	3,445

[1] Excludes military and other installations where the electric business is not the primary function.

As shown in table 2.2, ownership patterns vary among the different areas of the country, and ownership categories tend to be grouped in certain areas. For example, about one-fourth of the investor-owned utilities in the United States are in the Northeast Region, while nearly one-third of the public non-Federal utilities and cooperatives are in the West Central Region.

The types and sizes of electric systems constituting the power industry of the United States vary from state to state and from region to region, but most states are served by several types of power suppliers. The State of Kentucky is illustrative. Most customers in the State are served by three major investor-owned utilities. There are also a number of municipal and cooperative systems, including two generating cooperatives. The Tennessee Valley Authority (TVA) sells power at wholesale to several of

these municipalities and cooperatives. In addition, a special generating firm, Electric Energy Inc., which is owned by participating investor-owned companies, provides part of the generation for the large Atomic Energy Commission load in Paducah, Kentucky from its plant located in southern Illinois.

Table 2.2 shows that about 70 percent of the utility systems in the United States are engaged in distribution only. These systems include about 93 percent of the cooperatives, about 66 percent of the non-Federal government utilities and about 38 percent of the investor-owned utilities.

TABLE 2.2

Number of Electric Utility Systems by Ownership Classification, Region, and Function—1968

	Investor-Owned	Public Non-Federal	Federal	REA Coops	Total
Northeast					
Distribution only	38	123	....	26	187
All other	64	53	....	4	121
Total	102	176	....	30	308
East Central					
Distribution only	18	171	....	100	289
All other	32	75	....	6	113
Total	50	246	....	106	402
Southeast					
Distribution only	15	301	0	182	498
All other	25	28	[1] 2	8	63
Total	40	329	2	190	561
South Central					
Distribution only	16	228	0	190	434
All other	32	160	[2] 1	13	206
Total	48	388	1	203	640
West Central					
Distribution only	26	386	....	252	664
All other	51	297	([2])	19	367
Total	77	683	....	271	1,031
West					
Distribution only	41	160	0	143	344
All other	47	93	2	17	159
Total	88	253	2	160	503
Contiguous U. S.					
Distribution only	154	1,369	0	893	2,416
All other	251	706	5	67	1,029
Total	405	2,075	5	960	3,445

[1] Includes Southeastern Power Administration although it does not own any generating or transmission facilities.

[2] The Bureau of Reclamation has projects in the West Central, West and South Central Regions but, in order to avoid duplication, it is shown in the West Region where most of its projects are located.

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Investor-Owned Systems

The investor-owned segment of the electric power industry consists of approximately 400 systems. This is less than 12 percent of the nearly 3500 systems that comprise the total industry. In terms of any index of size, however, such as kilowatt-hours generated, kilowatts of generating capacity, or number of customers, the investor-owned systems clearly constitute the dominant segment of the industry.

The sizes of investor-owned systems range from the largest in the nation (apart from TVA) with annual sales in excess of 90 million megawatt-hours to some of the very smallest. The 200 largest systems own and operate more than 75 percent of the generating capacity and serve about 80 percent of the customers of the total electric power industry. The other slightly more than 200 systems have annual sales of less than 100,000 megawatt-hours each.

These large investor-owned systems are for the most part vertically integrated. The majority are independently owned and operated although 48 are subsidiaries of companies registered as holding companies under the Public Utility Holding Company Act of 1935, and an additional 32 are subsidiaries of companies which for various reasons are exempt from the provisions of that Act. These 80 subsidiaries are grouped into 32 holding company systems controlled by 18 companies, which are also operating electric utilities, and 14 nonoperating holding companies. The subsidiaries of the 14 nonoperating holding companies provide 22 percent of the generating capacity of the investor-owned segment of the industry. The 18 operating parent companies along with their subsidiaries provide an additional 17 percent.

The investor-owned systems generally serve prescribed areas pursuant to territorial franchises granted by state or local government agencies. These franchises are often not exclusive in the technical sense, but under most state laws a second investor-owned company cannot be franchised in a given territory without demonstrating that additional service is required by public convenience and necessity.

During recent years the electric power industry has been characterized by an increase in joint or coordinated actions and institutional arrangements. In addition to formal power pools and joint ownership arrangements, the industry has formed nine regional reliability councils and the National Electric Reliability Council as well as a number of planning organizations and coordinating groups. These are described in chapter 17.

Federal Systems

Five large Federal agencies market federally-generated power in the 48 contiguous states: the Tennessee Valley Authority, Bonneville Power Administration (BPA), Southwestern Power Administration (SWPA), Southeastern Power Administration (SEPA), and Bureau of Reclamation. They are important contributors to the electric power supply of this country. In 1968 the Federal systems had about 12 percent of total generating capacity and generated about 13 percent of the total electric energy. In these respects they are second only to the investor-owned systems.

The Federal Government's role in the electric utility field reflects a broad range of objectives. The TVA, established in 1933 to develop the resources of the Tennessee River Basin, was authorized to develop hydroelectric power resources in conjunction with navigation and flood control. Following essentially full development of the hydroelectric power potential of the basin, TVA developed a comprehensive power production system by adding fossil-fueled and nuclear generating plants.

It is now the nation's largest electric system, having approximately twice the generating capacity of the next largest, and is the only Federal agency with full responsibility to supply all the electric power requirements of a large geographical area. More than half of its power production is sold at wholesale to municipal and cooperative systems, with most of the balance going to industrial customers and Federal agencies.

Except for $65 million borrowed at long term from the Reconstruction Finance Corporation and the Treasury Department in fiscal years 1939–41, the TVA received all of its construction funds from Congressional appropriations prior to 1959. In 1959, the TVA Act was amended to permit the TVA to sell debt obligations in the open market and to require TVA to pay interest to the Federal Government on the net appropriation investment in power facilities.

This amendment also required repayment to the United States Treasury of such investment in annual installments of not less than $10 million per year for the first five years, $15 million per year for the next five years, and $20 million for each year thereafter until a total of $1 billion has been repaid.

The TVA Act gives preference to states, counties, municipalities, and cooperatives in purchasing power for distribution, and includes a provision specifying that any contract signed with an investor-owned electric company for purchase of TVA power can be cancelled on five years' notice if the power is needed by a preference customer.

Power marketed by the four large Federal power agencies other than the TVA is hydroelectrically generated and generally supplements the electric power supplies of other systems in the areas in which they operate. The Secretary of the Interior is the marketing agent for power produced by all Federal power projects other than TVA. Except for sales to a number of large industrial customers, nearly all of the power is sold at wholesale to other electric systems.

Bonneville Power Administration is the marketing agent for power from 33 Federal hydroelectric projects of the Bureau of Reclamation and the U.S. Army Corps of Engineers in the Pacific Northwest (26 of these are operating, 5 are under construction and 2 are authorized but not yet under construction). It has designed and built the nation's largest network of long distance, high-voltage transmission lines which serves as the main grid for all interconnected utilities in the Pacific Northwest.

The Southwestern Power Administration and the Southeastern Power Administration market the power produced at Corps of Engineers hydroelectric plants in the south central and southeastern states, respectively. SWPA has constructed some transmission facilities, but SEPA relies exclusively on transmission arrangements with other systems to market its power.

The Bureau of Reclamation operates several electric power systems, which include hydroelectric power plants built in widely separated areas in the Western States and Alaska. It has constructed transmission facilities to interconnect a number of its own plants, as well as those of others, in the Missouri Basin, the Southwest, the Far West and the Colorado River Basin; these projects are generally interconnected with one another, as well as with other neighboring systems.

Several Congressional Acts require the Secretary of the Interior, like the TVA, to give preference to public bodies and cooperatives in the sale of electric power. The idea of preference initially appeared in the Reclamation Act of 1906, which provided preference "to municipal purposes." Preference was made more specific in the TVA Act of 1933 and the Bonneville Project Act of 1937 which explicitly direct that preference be given to public bodies and cooperatives in the sale of the power. The Flood Control Act of 1944 contains a similar specification with respect to power generated at Corps of Engineers' projects and marketed by the Secretary of the Interior. Since public agencies and cooperative systems are given a statutory preference to buy the output of Federal projects, the extent of Federal system development has had a significant impact on the number, and power costs, of preference customers. Such costs reflect the lower fixed charges on capital investments in Federal projects by virtue of their lower interest costs and the absence of Federal income and other taxes.

Public Non-Federal Systems

Public non-Federal electric systems generate approximately 9 percent of total industry production and sell about 13 percent of the total electric energy. These systems, which include towns and cities, a small number of counties, special utility districts, and various kinds of state authorities, purchase approximately 35 percent of their requirements from the Federal systems and an additional 11 percent of their requirements from investor-owned systems. The number of systems under public non-Federal ownership reached its peak in the mid-1920's with nearly 3100 electric systems. The number declined rapidly to about 2200 by 1927. In 1968, there were 2075 such systems, of which 1369 purchased all of their energy requirements.

Municipal utilities are by far the most common form of the public non-Federal power entity. In the early stages of the industry's development, many towns and cities constructed electric systems to provide electric power for street

lighting and other public uses. Most of them subsequently constructed distribution facilities to permit retail sales. Municipal utilities vary in size from very small systems, serving only a few hundred customers, to the Los Angeles Department of Water and Power which serves over a million customers. In a relatively few instances (e.g. Cleveland, Ohio), a municipal system and an investor-owned system serve within the same municipality. However, territorial competition between municipalities and other systems often occurs upon expansion of municipal boundaries into fringe areas previously served by cooperatives or investor-owned systems.

During the 1930's and 1940's other government entities such as Public Utility Districts were established to produce and sell electric power. Some irrigation districts have included electric power supply among their activities for many years. Also, some states have entered the power supply field via special authorities such as the Arizona Power Authority and the Power Authority of the State of New York; the State of Nebraska is served entirely by public power entities and cooperatives.

Local government power agencies are exempt from Federal income tax and generally are not subject to state income tax. They are generally exempt from other state and local taxes but many of them make payments in lieu of taxes to their own local governments and provide power free or at reduced rates for street lighting, water pumping, and other municipal uses. Many of them also make other contributions to their local governments.

Cooperative Systems

The rural electrification program was initiated by Presidential Executive Order in 1935, and in 1936 legislation was passed establishing the Rural Electrification Administration as a lending agency. The REA has financed the construction of about a thousand rural electric service cooperatives in 46 states,[2] Puerto Rico, and the Virgin Islands[3]. They range in size from less than a hundred members to as many as 35,000. Though they have a total membership representing 10 percent of all electric power customers in the country, their total sales of energy are only about 4½ percent of the national total, and their generating capacity is about 1 percent of the total. Their distribution costs per customer have been relatively high because they serve an average density of only about four customers per mile of line. On the other hand, they have generally avoided the relatively high costs associated with inner-city congestion. They purchase 77 percent of their wholesale power requirements—45 percent from the government segment (including Federal systems) and 32 percent from investor-owned utilities; the remaining 23 percent is self-generated. In 1940, about 92 percent was purchased—41 percent from the government segment and 51 percent from the investor-owned segment; about 8 percent was self-generated. A large part of the government produced power comes from Federal hydroelectric projects over Federal transmission lines, or via transmission arrangements with neighboring utilities.

The REA program promoted the formation of small distribution systems purchasing their power at wholesale from existing electric utilities in their areas. As the distribution cooperatives grew in size, some of them organized generation and transmission (G&T) cooperatives for the construction of facilities to supply their own power. REA's stated policy is to make loans for G&T facilities only (1) where no adequate and dependable source of power is available to meet the consumers' needs, or (2) where the rates offered by existing power sources would result in a higher cost of power to consumers than the cost from facilities financed by REA, and where the power cost savings that would result from the REA-financed facilities bear a significant relationship to the amount of the proposed REA loan. The G&T cooperatives have gradually become an important power source; they now generate over 20 percent of REA-borrowers' total wholesale power requirements. There are about 50 such G&T's, some having as much as several hundred megawatts of generating capacity and participating as full members in regional power pools.

Competition between cooperatives and investor-owned utilities, and between cooperatives

[2] There are no cooperatives in Massachusetts, Connecticut, Rhode Island or Hawaii.

[3] There are 32 electric service cooperatives which have repaid their loans from REA in full and are under no further obligations to that Agency. There are also about a dozen small cooperatives which were originally organized without REA loans.

and municipally-owned systems, is reflected in attempts to attract new customers into their respective service areas and to acquire new service areas. Competition has become acute in some places with the movement of industry into suburban and farm areas. In some cases, where a city is expanding its boundaries, the system serving within the city has taken the position that the newly acquired citizens are its customers. But if the new citizens are already served by a cooperative, the cooperative has been reluctant to give them up, arguing that it took the risk of initiating service at a time when no other system was willing to serve.

Competition is even more evident in the attempts of each type of utility to attract large, profitable industrial loads. In the past, some of the investor-owned suppliers restricted, through provisions in their wholesale power contracts, the resale of power by municipals and cooperatives to large-use customers. In the Georgia Power Company case[4] and the Mississippi Power Company case,[5] the Commission has ruled such provisions to be unlawful.

At the Federal level, controversy has centered on legislation dealing with the scope of the REA program and the 2 percent interest rate charged, the scope of Federal power projects which are the main source of energy purchased by cooperatives, and the tax provisions pertaining to the REA cooperatives. Although the REA cooperatives, like other consumer cooperative ventures, do not operate for profit and therefore pay no Federal income tax, they are liable in most instances for state and local property taxes. In some states they also pay gross revenue taxes, sales taxes, and other state and local taxes.

[4] 35 FPC 436, 35 FPC 818 (1966), Docket Nos. E–7099 and E–7193. The Commission's decision in this case was upheld by the Fifth Circuit Court of Appeals in 373 F.2d 484 (CA 5, 1967).

[5] Docket No. E–7112, Opinion No. 593, issued February 18, 1971.

Changes in Industry Size, Structure, and Ownership

Table 2.3 shows the relative sizes of electric systems, segregated by type of ownership, for 1962 and 1968.

Table 2.3 shows that the number of electric systems in all segments of the industry decreased between 1962 and 1968. The investor-owned segment showed the greatest change with a decline of 75 systems, or about 15 percent. Next in significance was the reduction of 49 systems, or 2.3 percent, in the public non-Federal segment. The change in the number of systems in the cooperative segment was relatively minor, and the number of Federal systems did not change. Undoubtedly, technological advances in generation and transmission, resulting in rapidly increasing sizes of new generating units and substantial in-

TABLE 2.3

Number of Electric Utility Systems in the Contiguous U.S. by Size and Ownership Classifications

Annual Sales (millions of MWh)	Investor-Owned	Public Non-Federal	Federal	REA Cooperatives	Total
1962					
Over 10	18	0	3	0	21
1–10	88	20	2	1	111
0.1–1	85	136	0	64	285
Under 0.1	289	1,968	0	904	3,161
Total	480	2,124	5	969	3,578
1968					
Over 10	35	2	3	0	40
1–10	100	34	2	5	141
0.1–1	61	234	0	150	445
Under 0.1	209	1,805	0	805	2,819
Total	405	2,075	5	960	3,445

creases in transmission voltages, have provided a significant impetus to these changes.

There has also been an important, although gradual, change in industry composition with respect to functions performed. In 1962, 2315 of the 3578 systems (approximately 64%) were engaged in distribution only. In 1968, 2416 systems of 3445 (or approximately 70%) were engaged in distribution only. In general, two factors have contributed to this trend. First, the decline of 75 systems in the investor-owned segment matched closely the decline in the number of investor-owned systems that had been generating their own power. Second, over 100 of the systems in the non-Federal government segment withdrew from production of electric power and became "all-requirements" purchasers of power from others. These trends can be expected to continue as the growing scale of generation and transmission facilities requires increasingly large capital investments.

The changes in the electric power industry structure described above lead directly to the question of the changes to be anticipated over the next several decades. Some have suggested that technological and economic forces are likely to cause the industry gradually to group itself into as few as 15 to 20 large integrated systems, in part because of economies of scale and improved reliability attainable when systems are planned and operated on a coordinated single system basis. Generally, those who take this position feel that it is very much in the public interest that this occur. They, therefore, tend to favor acquisition of small systems by their larger neighbors and to favor most mergers among contiguous larger systems.

Others take the view that one of the major strengths of the electric power industry lies in the diverse and pluralistic nature of its ownership. Those taking this view believe that it is desirable for the industry to continue to consist of many systems of various sizes and various types of ownership, partly because competition among systems is maintained, and partly because consumers can deal with a more localized management that may be more responsive to their needs. In addition it is argued that when systems become very large they may become more difficult to regulate, especially at the state level. Proponents of a diverse and pluralistic industry believe that most of the advantages of centrally owned and operated large systems can be obtained by means of power pools, joint ownership and other coordination arrangements among smaller, individually owned systems.

Still others feel that we can have the best of two worlds—larger, more efficient generating and transmission facilities, coordinated and controlled by a tight centralized structure, and at the same time continued local customer service through small and autonomous marketing companies, public agencies or cooperatives, or through highly individualized and decentralized divisions of a larger authority.

The extent to which the trend toward greater concentration in the electric power industry can be expected to continue will depend in large measure upon the relative weight given by the industry, the regulatory agencies, and the general public to these points of view.

Combination Electric and Gas Utilities

The 78 investor-owned utilities, Classes A and B,[6] which sell both gas and electricity play an important role in the United States energy market. In 1967, these combination companies accounted for 43 percent of total kilowatt-hour sales and 50 percent of total electric operating revenues in the investor-owned segment.

In general, the electric portion of these combination utilities is larger in terms of revenues and investment in plant than the gas portion. In 1967 the gas plant owned by combination companies was only 14.9 percent of the value of the combined electric and gas plant, although gas revenues were 25 percent of total revenues. This relationship is primarily due to the large investment in production and transmission facilities required for the electric service provided by combination companies, in contrast to the smaller investment in distribution facilities for the gas service they typically provide.

In table 2.4, combination utilities are divided into three size categories (according to sales in MWh) to distinguish their operating characteristics. Companies in the "large" category include nine out of the ten largest investor-owned electric utility operating companies in the United

[6] Class A utilities have annual electric operating revenue of $2,500,000 or more; Class B utilities have annual electric operating revenue of $1,000,000 or more.

TABLE 2.4

Selected Characteristics of Classes A and B Investor-Owned Combination Utilities—1968

Annual Sales (millions of MWH)	No. of Companies	% Electric Revenues of All Combination Companies	% Gas Revenues of All Combination Companies
Over 10 (large)	13	63.4	48.9
1–10 (medium)	47	34.8	44.1
Under 1 (small)	19	1.8	7.0
Total	79	100.0	100.0

States measured by total assets. These nine largest companies provide about 55 percent of the electric revenues and about 44 percent of the gas revenues of all combination companies.

There is a variance of views concerning the claimed benefits or detriments associated with combination gas-electric companies. Those favoring separation of gas and electric services maintain that the public interest is served best when gas and electric utilities actively compete for household, commercial, and industrial markets. These markets include space heating, water heating, cooking, air conditioning, refrigeration, clothes drying, and outdoor lighting, as well as steel furnaces, industrial process heating, pipeline pumping and the like. This line of analysis contends that greater competition stimulates more effective management and leads to lower prices, expanded output, improved service, greater operating efficiency, and more intensive research and promotional activities, all giving the consumer greater freedom of choice.

The advocates of combination companies contend that they have lower costs than single energy utilities. The proponents point to economies of joint operations such as meter reading, appliance inspection, service departments, sales and administrative staffs, and use of a single trench for underground distribution. In addition, they claim flexibility in solving peaking problems and greater revenue stability, and point to advantages of dealing with only one utility where a customer can obtain comparative information concerning the preferable form of energy for specific needs.

Regulation

While the electric power industry has been subject to regulation of various of its activities almost since its inception in the late 19th Century, the scope and tempo of regulatory activity has increased during the last few years. This has resulted in large part from: (1) concern for the preservation and protection of the environment, (2) concern for the reliability of electric power supply, (3) the growing importance of nuclear power in the total power supply, and (4) the rapidly rising cost of fossil fuel and capital in the context of a generally inflationary economy.

Since the early part of this century, major responsibility for the regulation of the electric industry, especially the investor-owned segment, has rested with the state utility commissions. At the present time nearly all of the states[7] have established regulatory commissions having some authority for regulation of the investor owned electric utility systems. However, less than half of the state regulatory commissions have authority to regulate publicly owned and cooperatively owned systems. The scope of the authority of state commissions to regulate electric utility systems varies considerably among the states, but many state commissions have rather broad powers including the regulation of rates, accounting, security issues, safety and adequacy of service, as well as authority for certification of major property additions, initiation and abandonment of service and allocation of territory.[8]

At the Federal level several agencies have important responsibilities for regulating specific ac-

[7] The exceptions are Minnesota, Nebraska, Texas and South Dakota. Various forms of local regulation are authorized in these states as well as in a number of other states which do have state commissions.

[8] For details see Federal Power Commission, *Federal and State Commission Jurisdiction and Regulation, Electric, Gas, and Telephone Utilities,* FPC S–184, Washington, D. C., 1967.

tivities of electric power systems. These include among others the Federal Power Commission, the Securities and Exchange Commission, and the United States Atomic Energy Commission.

The Federal Power Commission has authority to provide certain types of economic regulation of investor owned electric utilities. It is directed to encourage the most efficient and productive utilization of all of the nation's electric energy resources. Its responsibilities include the licensing of virtually all non-Federal hydroelectric projects, the regulation of interstate wholesale rates and services and the regulation of corporate activities, accounts and reports of systems subject to its jurisdiction.

The Federal Power Act makes the Commission's responsibility that of ". . . assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources. . . ." This National Power Survey represents one part of the Commission's total effort to carry out that responsibility. An equally important part of that effort has been the implementation by the Commission of a program for adequacy and reliability of electric power resources, Order No. 383–2, Policy Statement—Reliability and Adequacy of Electric Service, issued April 10, 1970, 43 FPC 515. This order provides for: (1) the annual reporting of data by the nine regional reliability councils bearing upon future reliability and adequacy of service in each council region including projections and bulk power supply expansion plans reaching ten years into the future, and (2) participation of state and Federal regulatory personnel in the deliberations and work of the nine councils including various committees established by participants in these councils.

The Securities and Exchange Commission regulates certain phases of the activities of public utility holding companies and their subsidiaries engaged in the electric utility business including accounting, security issuances, mergers, service company arrangements and intercompany transactions. The holding company device has been receiving considerable attention in recent years as a method of corporate realignment and consolidation in the electric utility industry. Currently there are several proposed consolidations pending before the Securities and Exchange Commission which are likely to have an important bearing upon the future ownership structure of the electric power industry.

The Atomic Energy Commission has authority to regulate construction and operation of all nuclear reactors regardless of their ownership—public, private, or cooperative. Its regulatory responsibilities and activities are discussed at some length in chapter 6. Recently, there has been increasing controversy concerning the environmental effects of the operation of nuclear power reactors. Disagreement has arisen concerning appropriate radiation levels associated with plant operation. There have also been questions concerning possible adverse thermal effects resulting from cooling requirements of the nuclear projects. A further source of controversy relates to the requirement of the Atomic Energy Act of 1954 as amended involving antitrust aspects of proposed nuclear projects.

At the Federal level, concern with environmental factors has taken tangible form in the creation of the Environmental Protection Agency [9]. Also, the increased attention has derived in part from the enactment of the National Environmental Policy Act of 1969 [10]. This legislation requires the preparation and distribution of an environmental statement in connection with any major Federal action significantly affecting the quality of the human environment, including thorough evaluation of alternative courses of action.[11] The Federal Power Commission had employed substantially equivalent procedures in regard to its hydroelectric licensing responsibilities prior to the passage of the National Environmental Policy Act. However, to effect implementation of the requirements of that Act the Commission issued

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[9] The responsibilities and activities of this agency and predecessor agencies with respect to air and water quality control are described in detail in chapters 10 and 11.

[10] 42 U.S.C. 4321, *et seq.*

[11] Section 102 (2) (C) of the statute prescribes an analysis of five essential points as part of the detailed statement. They are: (i) the environmental impact of the proposed action; (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented; (iii) alternatives to the proposed action; (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity; and (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

its Order No. 415 on December 4, 1970—which was later revised in Order No. 415B issued November 19, 1971.

At the state level, increasing public concern for the quality of the environment is evident in the actions of state legislatures in recent years to strengthen the role of the state regulatory commissions and other state agencies in controlling environmental effects of electric power facilities.[12] Of the approximately 30 state commissions which require the issuance of certificates for the construction of power plant and transmission lines, at least two-thirds now give consideration to the impact of the proposed facilities on various environmental factors. In at least 9 states, utilities must obtain separate authorization from other state agencies as well as the regulatory commissions.

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[12] A state by state summary of the authorities and activities relating to environmental controls affecting electric utilities may be found in *Electric Power and the Environment*, a report sponsored by the Energy Policy Staff, Office of Science and Technology, Washington, D. C., August 1970.

Already heavy expenditures by electric utilities for environmental pollution control facilities, higher fuel costs relating to environmental standards and higher interest costs in the context of a generally inflationary economy have resulted in an unprecedented number of applications to state and Federal regulatory agencies for rate increases. During the year ended June 30, 1971, about $1 billion of annual electric rate increases were put into effect. Although the regulatory burden of dealing with a workload of this magnitude has been severe, it is apparent that the more difficult problems facing the regulatory agencies for the future transcend the traditional problems of rate and economic regulation. In general, these problems encompass the need to assure an adequate and reliable power supply without undue adverse impact upon the environment. It is apparent that the interests of the consumer, the utility supplier and the general public in a healthy economy served by adequate and reliable power resources depend upon the timely and effective resolution of these problems.

CHAPTER 3

THE PROJECTED GROWTH IN THE USE OF ELECTRIC POWER

Introduction

The projections of electric power use in this chapter are a consensus of expectations of the general magnitude of future loads which the electric utility industry should prepare to serve. They are not intended to be forecasts in the formal sense. The extent to which actual energy requirements depart from projections in the report will depend upon many intangibles, but it is certain that substantial increases in electric energy production will be required to achieve national goals such as clean air and water, better housing, and a higher standard of living for lower income groups. The projections in this chapter cover demands of ultimate consumers—that is, the external loads that utilities must meet. They do not include internal energy consumptions such as pumping energy for hydroelectric pumped storage projects, station uses for environmental protection devices and other purposes, and transmission losses. The costs of these later items, however, are included in the chapter 19 determination of the unit cost of power to the ultimate consumer.

Characteristics of Electric Loads

There are wide variations among the daily and seasonal electric loads of the Nation's utility systems because of different proportions of energy consumption by residential, commercial, and industrial customers, different cycles of daily social activity, and different weather patterns. System loads normally are highest during the weekdays and drop off on weekends. Systems which serve predominantly residential and commercial customers usually experience a rapid load buildup in the early morning, a reduction during midday, a peak during the early evening hours, and very low loads after midnight. A system which serves a heavy industrial load usually experiences smaller diurnal variations. In recent years, many systems have experienced a change in the character of their daily loads, due primarily to electric air conditioning in summer and electric space heating in winter. These changes have increased peaks and extended the duration of daily and seasonal near-peak demand levels. On an annual basis, however, they have sometimes increased the relative difference between average and peak loads, thus decreasing system load factors.

While the daily, weekly, and seasonal loads differ among utilities, each system has a recurring and reasonably predictable pattern of load requirements. Figure 3.1 is a peak-week load curve of a large utility with a weekly load factor of about 80 percent, on which is shown hour-by-hour loads in the sequence in which they occur. Monthly and annual load factors of this same system would be much lower. About 50 percent of the weekly maximum demand is continuous and is called the system's "base load."

The intermediate system load amounts to approximately 30 percent of maximum demand and is continuous for periods of 12 or more hours on weekdays. The peak portion of the load, amounting to about 20 percent of maximum demand, can occur over a period of less than one hour to about 12 hours.

The maximum one-hour load in each month for two regional groups of electric systems is illustrated graphically in figure 3.2. The South Central Region has a composite summer peak, and the West Region has a winter peak. A comparison of corresponding loads in other years shows that each group has a well-defined annual pattern of peak loads. The monthly peak loads of other regional groups throughout the country follow patterns generally somewhere between the extremes shown on figure 3.2.

WEEKLY LOAD CURVE

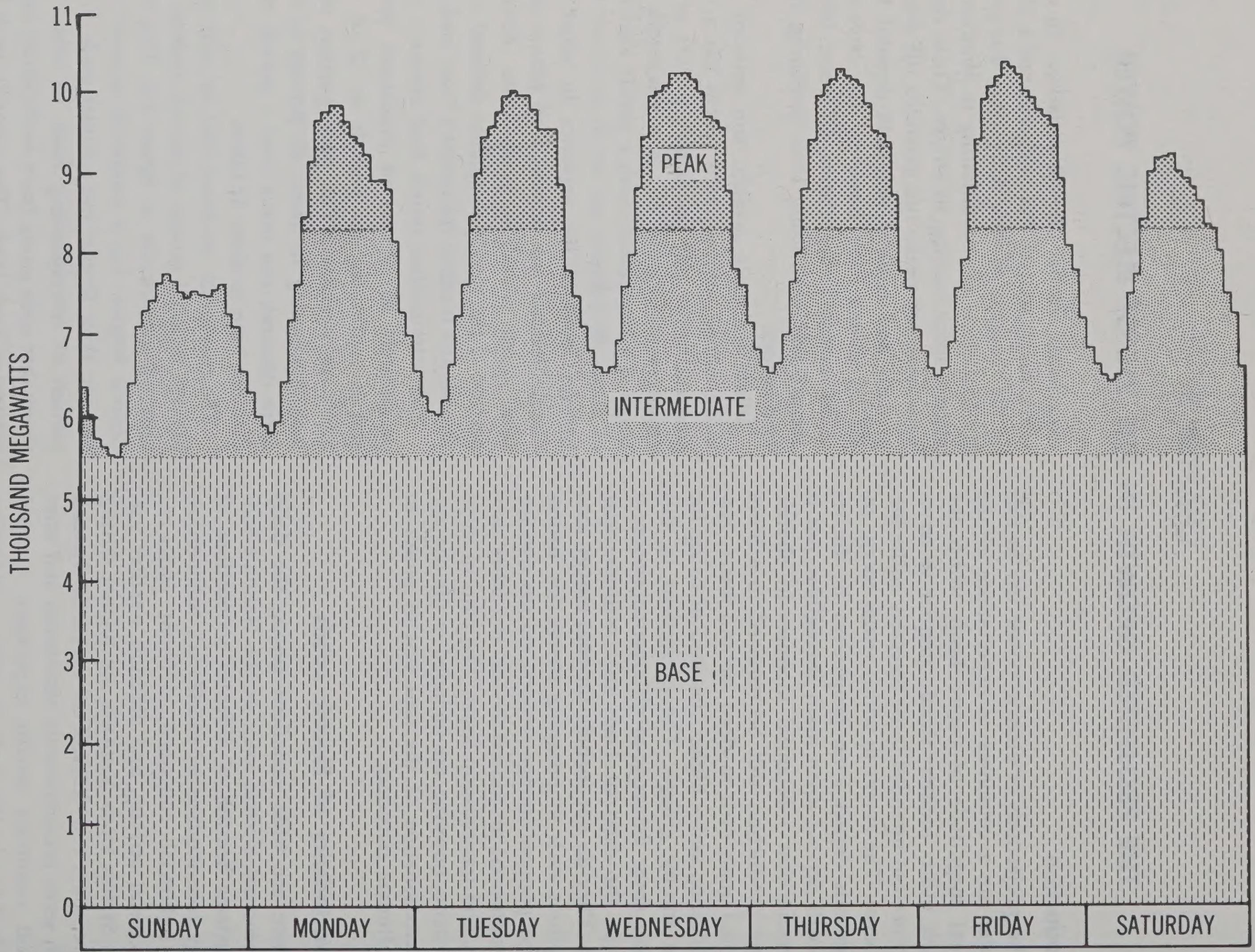

Figure 3.1

ESTIMATED 1970 MONTHLY PEAK DEMANDS

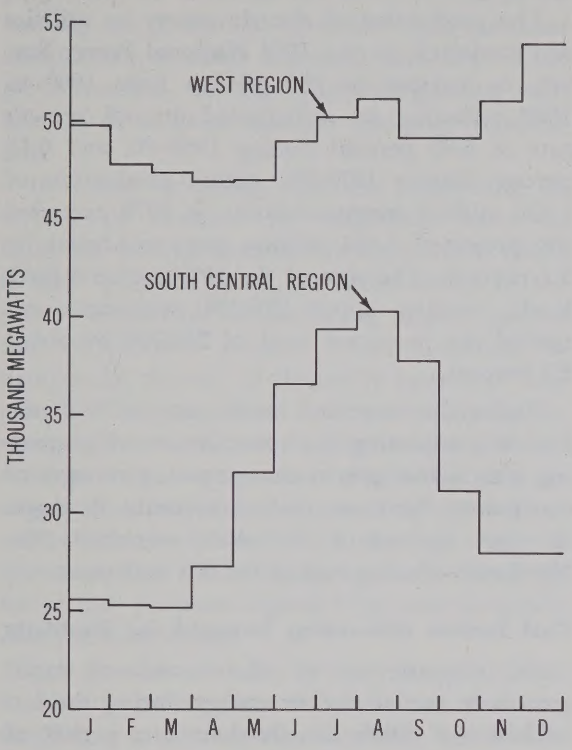

Figure 3.2

Demand for Electricity

Since the inception of the electric power industry in the early 1880's, electric power loads have been growing at an average annual rate of about 7 percent, resulting in a doubling of loads about every ten years. This growth has been related to two basic trends—a population growth rate of about 1.3 percent per year, and mounting per capita use. Population growth is a significant factor in determining the ultimate size of the energy market. Other major factors affecting the demand for goods and services, including electric energy, are technological advances, increases in personal income, and individual preferences on how available income will be used. The relatively low competitive cost of electric energy has undoubtedly contributed to the phenomenal increase in demand, but convenience, cleanliness, versatility, and reliability of electrically powered equipment have generally been the major influences on individual and corporate decisions to use electricity.

Since 1950, disposable personal income in terms of constant dollars has almost doubled. In current dollars about 40 percent of all American families now earn more than $10,000 per year compared to 3 percent in 1950. The average American is better educated, better informed, and economically more secure than ever before. In the future more and more tasks will be performed by machines and energy demands will be more sensitive to changes in both economic activity and technology. It took about 20 years to develop and market the television set, but comparable new products now under development in the laboratories are expected to emerge from assembly lines in only a few years. Current and prospective income levels will permit people to purchase new products in increased numbers. More and more electricity is being used in manufacturing new products, and often the products themselves consume electricity in their operation.

Per capita consumption of electric energy in this country from 1920 to 1970, and projections to 1990, are shown on figure 3.3. Growth in total energy consumption in the United States and the percentages of all energy used to produce electricity are shown in figure 3.4. The

ANNUAL PRODUCTION OF ELECTRIC ENERGY PER CAPITA — UTILITY AND INDUSTRIAL

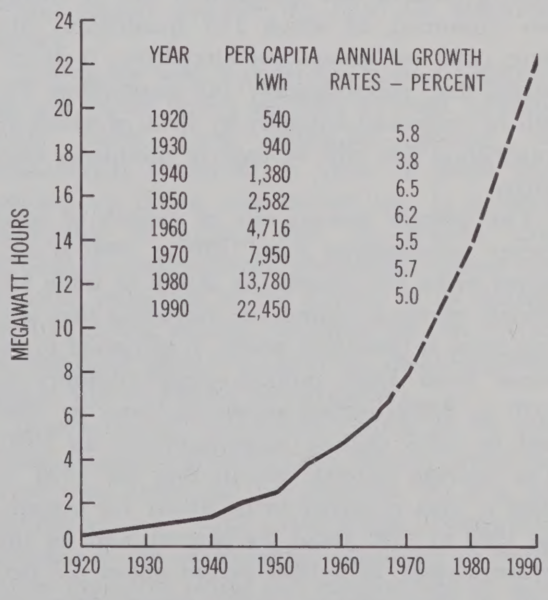

Figure 3.3

U.S. ENERGY CONSUMPTION
1920 - 1990

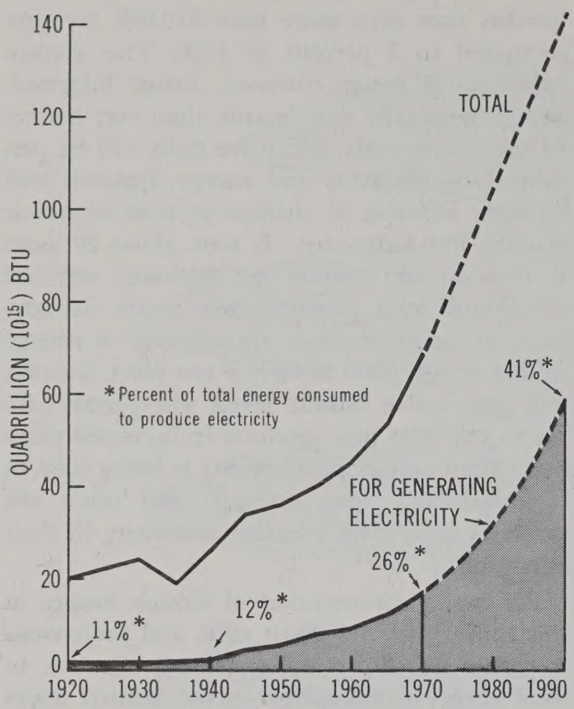

Figure 3.4

total energy shown includes hydroelectric generation by converting kilowatt-hours to Btu at the same rate as for fossil-fueled generation. In 1970, a total of 68.8 quadrillion Btu of energy was consumed, of which 17.7 quadrillion Btu were used for generating electricity. It is expected that approximately 143 quadrillion Btu will be consumed annually by 1990, of which 59 quadrillion Btu will be used in producing electricity.

The average annual rate of growth of total energy consumption from 1970 to 1990 is estimated to be 3.7 percent. As shown in table 3.5, electric energy consumption, including that self-generated at industrial plants, is projected to increase from 1,642 million megawatt-hours in 1970 to 3,202 million megawatt-hours in 1980 and to 5,978 million megawatt-hours in 1990. The average annual growth rate for 1970 to 1980 is thus expected to be about 7.0 percent, for 1980 to 1990 about 6.4 percent, and for the entire 20-year 1970–1990 period about 6.7 percent. At these rates of growth, energy consumed in the United States to produce electricity would increase from 26 percent of total energy consumption in 1970 to 41 percent in 1990.

The production of electric energy by utilities was projected, in the 1964 National Power Survey, to increase by 253 percent from 1960 to 1980 reflecting an anticipated annual growth rate of 6.92 percent during 1960–70, and 6.15 percent during 1970–80. Actual production of 1,535 million megawatt-hours in 1970 exceeded the projected 1,484 million megawatt-hours by 3.1 percent. The sum of the 1970 regional peak loads, totaling about 276,000 megawatts, exceeded the projected total of 270,000 by about 2.2 percent.

Higher-than-expected loads, coupled with delays in completing the construction of generating plants and greater-than-expected outages of equipment, have resulted in capacity shortages in some regions of the country—notably the Northeast—during each of the last four years.

Cost Factors Influencing Demand for Electricity

An examination of the causes of rapid growth in use of electric energy during the last half of the 1960's reveals that in a period of sharply accelerating inflation in the price of consumer goods, the average price paid per kilowatt-hour for electricity continued to drop, both in current dollars and in adjusted or "constant value dollars."

Because the electric utility industry is capital-intensive in such high degree, and because lead times in bringing new capacity on-line are so long, the impact of inflation on electric rates tends to lag the consumer price index by several years. Pressures of continuing inflation—including higher construction costs, higher money rates, higher prices for fuel, and the large outlays required to meet new environmental standards—are causing current dollar costs of generating and delivering electricity, albeit belatedly, to rise sharply. These cost increases are not being offset by scale economies, technological advancements, and improved operating efficiencies as they have been in the past. A result of this situation is a wave of recent applications to regulatory bodies for permission to increase electric rates.

This reversal in the trend of the price paid for electricity must be taken into account, along with the probable price performance of competi-

tive sources of energy, in re-examining the 1964 projections of electrical use to 1980, and in extending the projections to 1990. While customer acceptances of many electrical uses show little price elasticity, certain large and growing markets (such as space heating) are price competitive.

It is not surprising that the continuing increases in demand for electricity have, in colliding with environmental imperatives, raised a basic question as to the acceptability in the public interest of a continuing annual growth rate of about 7 percent. Various devices for dampening the use of electricity have been suggested. They range from consumer education on energy conservation to the elimination of lower rates for large-use customers (including, as some suggest, the imposition of actual rate penalties) —all with the objective of slowing electrical growth and/or discouraging the use of electricity for certain purposes regarded by some as unnecessary or undesirable.

It is possible that the current sharp increases in electric power costs will result in some reshaping of rate structures. However, it would be shortsighted to view electric energy growth in terms of cost-price adjustments, or to question the rate of growth without considering the Nation's overall energy needs and supplies.

Environmental Protection

There have been proposals to retard the growth in electric energy use in order to lessen the impact on the outdoor environment. However, substantial increases in electric energy production will be required to achieve national goals calling for clean air, clean water, safer highways and streets, better housing, and a higher standard of living for low income groups. Electric power is required for recycling solid waste products and for purifying waters used in sewage and industrial processes. It is essential in such environmental protective and improvement processes as those under development for the desulfurization of fossil fuels or the decontamination of the gases which result from the combustion of fuels and for a myriad of other purposes to protect or improve the environment. Rather than being depressants, environmental factors may act as stimulants to use of electricity in the decades ahead. Electricity may become recognized as one of the best means of improving environmental conditions. In its favor are cleanliness, efficiency, ease of transmission, and its generally lesser impact on the environment than alternative energy forms. For example, substitution of electric space heating for individual fossil fuel furnaces in urban dwellings and commercial establishments could have a significant beneficial effect on urban air quality. Properly planned expansion of the use of electricity can contribute to maintaining a favorable environment physically, socially, and economically.

A stimulating effect on electric energy use could be expected if adequate supplies of natural gas are not available for household heating, if national policy should reduce oil imports, if current research on new types of nuclear or other methods of generating power is rewarded by a major breakthrough, or if conversion of the energy in gas and oil into central station electric energy becomes less costly than on site use of these fuels. Each of these considerations would tend to make central station electricity more attractive to the consumer. Undoubtedly, the biggest imponderable with respect to future growth in electrical energy use lies in the creativity of American inventors—and thus in unidentifiable "new developments." For example, any significant advance in the means of utilizing central station electricity as the source of energy for automobiles, or a decision to use it in a widespread program of gasification of coal, would greatly increase the need for electrical energy.

During the next two decades national emphasis and thrust is not expected to shift substantially away from economic growth as traditionally conceived in terms of goods and services for public and private use. It is more reasonable to expect that the Nation will achieve its environmental objectives without any material reduction in the quality of its electric services in the process, although the cost to the consumer of energy in any form, including electricity, will necessarily be increased.

Irrespective of the future course of the national economy, growth of the electric power industry is likely to be retarded if lack of agreement on what constitutes reasonable changes in the environment continues to cause major delays in siting and construction of new generation and transmission facilities. Repeated brownouts could lead to loss of confidence by

the investing public so that financing the needed expansion could become a serious problem, thus further compounding the difficulties of providing additional capacity on schedule. On the other hand, repeated brownouts could lead to consumer pressures for more expeditious solutions of the problems impeding the development of those facilities found to be necessary in a properly balanced program.

Environmental considerations affect both the electric utility industry and the consumers. Removal of air contaminants, use of substitute low-sulfur fuels, construction of facilities at environmentally favorable sites that are higher cost locations with reference to load centers, use of cooling towers or ponds, undergrounding of facilities, and meeting other environmental control criteria are major factors contributing to the current trend toward higher consumer rates. If the cost of electricity increases significantly, the future market for such services as electric space heating and cooling and electrified transportation might be weakened. The anticipated economies resulting from improved load factors and high volume production would be reduced, and rising costs of services could cause a measurable slowdown in the consumer's demand for electricity.

Weather

The weather, particularly the highly unpredictable daily summer and winter temperature variation, is one of the dominant factors which determine the magnitude of daily peak electric loads. In recent years, as electric space heating and cooling have gained in popularity, the forecasting of these daily peak loads has become increasingly more difficult. Historical records demonstrate that fluctuations in daily temperatures have caused some system peak loads to vary by more than 20 percent when other factors affecting peak loads remain relatively constant.

Daily temperatures influence both the magnitude and duration of the peaks. The air conditioning load in the summer is high from midmorning to early evening and winter heating loads are heavy from early morning to late evening. If a system's peaking capacity is designed to supply high peaks of short duration, it can become inadequate when called upon to serve peaks of long duration. Thus, weather sensitive loads are introducing system planning problems that can be solved only by taking the weather factor more fully into account. These weather effects are significant because load forecasts influence the scheduling of maintenance and additions of generation, transmission, and distribution facilities.

Potential Load Building Developments

The continuing shift of energy use from primary fuels to electricity is an important factor to consider in projecting electric energy requirements to 1990. The increasingly urban society in America, and its overwhelmingly industrial orientation, encourage the shift and foretell its continuation for at least the two decades considered in this report.

Industry

The manufacturing industries are expected to experience the most dramatic impact from new uses of electricity, as illustrated in the following sections.

Process Heating

New developments in the field of solid-state technology have made possible a silicon rectifier capable of handling 1,000 kilowatts compared to an available capability of 16 kilowatts in 1958. Developments of this type can open the whole field of process heating by introducing new economies in rolling mill operations and in those fabricating techniques calling for precise control of local heat applications. The load potential of process heating is expected to be greater than that of industrial lighting and industrial drives which revolutionized the manufacturing industries in the past.

Electric-Arc Steel-Making Furnace

The steel industry appears to be on the verge of a revolution in the steel-making process in which more extensive use would be made of electric-arc furnaces. The change is anticipated primarily because of several processes being developed which are demonstrating significant cost reduction in ore handling operations. These new processes, some of which are already in use, roast iron ore in a reducing atmosphere of 1,600–1,900°F. to produce a metallized sponge iron of 85 to 98 percent purity. Sponge iron or "prereduced ore," as well as scrap metal, are excellent charges for the electric furnace. That fact,

plus the control advantages of the electric furnace and its characteristic as the best device for melting cold metal, is expected to channel most of the sponge iron and scrap metal to the electric-arc steel-making furnaces. The steel industry is anticipating large-scale production and wide availability of prereduced ore during the 1970's, followed by a rapid replacement of open hearth processes by the electric-arc furnace. This change, although instigated primarily for economic reasons, also reduces air pollution problems traditionally associated with steel industry furnaces.

In 1967 total raw steel production in the United States was 127.2 million short tons, of which 15.1 million tons were produced in the electric arc furnace and the remainder by the open hearth and basic oxygen processes. By 1990 various analysts of the industry project a raw steel production of about 200–210 million tons, of which about 100 million tons will be produced in the electric-arc furnace.

Based on an energy requirement of about 400 kilowatt-hours per ton of steel produced, an annual total of about 40 million megawatt-hours will be required by electric-arc furnaces by 1990. The electric-arc furnace will also be used to convert prereduced ore to pig iron, but it is expected that competition from the standard blast furnace will limit production by this procedure to about 4 million tons.

Induction Heating in Steel Industry

During the next two decades it can be expected that large-scale induction heating will take over a significant portion of the heating and temperature control functions in hot-rolling operations of the steel industry. Induction heating can reduce heat-up time of large slabs to less than one hour rather than five to six hours now required in fuel-fired soaking pits. Less scaling of the slabs, more uniform temperatures throughout a slab, and precise control of the rolling temperatures, should result in increased production and improved quality.

The world's largest induction heating installation for reheating steel slabs prior to hot rolling was placed in commercial operation in June 1969. The installation can heat 650 tons of steel slabs per hour to over 2,300°F. The electric energy consumption is about 310 kilowatt-hours per ton. Production of hot-rolled products could increase from 99.2 million tons in 1966 to about 150 million tons by 1990. It is estimated that by 1990 about two-thirds of the tonnage will be subjected to the electric induction heating process, which will require about 30 million megawatt-hours of electric energy annually.

Electro-Organic Synthesis

During the next two decades, the electrochemical industry may resolve some of the problems of electro-organic synthesis now associated with the chemical processes. If the intensive five-year research program currently being considered by the industry is inaugurated and proves successful, substantial economic benefits would be introduced in the manufacture of plastics and industrial chemicals. Before 1990, the electric utility industry may begin to feel the impact of high electric current synthesis processes on utility loads.

Other Industrial Applications

Many new industrial operations, awaiting the challenges of opportunity and the pressure of necessity, will undoubtedly be introduced during the next 20 years. Invention and innovation can be expected to continue and the demands for electric power will increase as technological developments mature. Those listed below are suggestive, but certainly not exhaustive, examples.

Infrared electric lamps are being used to speed up paint applications, making possible several applications per day.

In St. Louis, Missouri, electric resistance heating of a two-and-one-half mile pipeline used to deliver asphalt from a refinery to a barge increases the effective capacity of the line by increasing temperatures as much as 325°F.

In Japan a technique for heating pipelines electrically, known as Skin Electric Current Tracing, has been developed recently. Heat is generated when an electric current is caused to flow on the inner surface of a tube welded or cemented to a pipeline. The technique is currently being used to heat pipelines of 2- to 32-inch diameters carrying crude oil, heavy fuel oil, lubricants, and viscous food products over distances ranging from one-half to six-and-one-half miles while maintaining temperatures between 86 and 140°F. Power consumption ranges from 10 to 50 watts per foot of tubing and as many as six tubes would be used on a 36-inch pipeline.

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Annual energy requirements for pumping at pumped storage hydroelectric plants are expected to amount to nearly 100 million megawatt-hours by 1990, only about two-thirds of which will be returned to the systems involved. It is also noteworthy that auxiliaries, such as cooling towers, precipitators, stack-gas scrubbers, and other devices currently being installed at most thermal plants to reduce adverse environmental effects not only consume power but reduce plant efficiencies. While capacity needs are based on "net" plant capabilities, the effect of these auxiliary facilities is to increase the total amount of capacity that must be built and operated.

Residential Electric Requirements

Electric energy used by residential consumers, including farm residential, is projected to increase from 270 million megawatt-hours in 1965 to 1,467 million megawatt-hours in 1990. A significant factor in this projected increase is the growing number of residential customers who live in all-electric homes, where the average customer in the contiguous United States, according to 1968 reports, consumed three times as much electric energy as the average residential customer. In 1970, the average all-electric home customer used about 20,000 kilowatt-hours of electric energy. By 1990, the corresponding average annual use is expected to be 33,000 kilowatt-hours, slightly more than twice the average annual use of all residential customers.

The projected increase in use of electricity in all-electric homes is attributable in part to increases in power-consuming appliances, but it also reflects the northward shift of the geographic center of all-electric installations. In the past, most all-electric homes have been in the South where air conditioning is increasingly considered a necessity instead of a luxury, and where heating loads are relatively light. It is expected that there will be a continuation of the current trend toward increased installations in the northern part of the country, where considerably more energy is needed for heating than for cooling, and where the total consumption of electricity in all-electric homes is considerably higher than in the South.

The estimated growth in all-electric dwellings is shown in table 3.1. Approximately one-third of the new dwellings constructed in 1970 used electricity for heating and cooling. The projections are based on the assumptions that 40 percent of new dwellings constructed in the 1971–80 decade will be all-electric, 50 percent constructed in the following decade will be all-electric, and that there will be about half as many conversions as there are new installations.

TABLE 3.1

Electrically Heated Dwellings in the United States 1964–1990

Year	Millions of Dwellings
1964	2.2
1966	2.7
1968	3.4
1970	4.2
1980	12.5
1990	24.0

By 1990 a significant increase can be expected also in the electric energy requirements of the homes that are not all-electric. The percent of homes that have major electric appliances will continue to increase until saturation is approached. Also, many of the homes that are not all-electric will utilize electric space heaters to supplement on-site heating by fossil fuels. The changes in market saturation in major appliances between 1960 and 1970 are shown in table 3.2.

Table 3.3 is a list of the approximate wattage ratings and estimated 1969 annual kilowatt-hour

TABLE 3.2

Market Saturation Levels for Selected Electrical Appliances[1] Contiguous United States

[Percent]

Appliance	1960	1965	1970
Electric range	37.3	42.4	55.5
Water heater	18.9	23.4	31.6
Freezer	23.4	27.2	31.2
Air conditioner	15.1	24.2	40.6
Washer	85.4	87.4	92.1
Dryer	19.6	26.4	44.6
Vacuum cleaner	74.3	83.5	92.0
Dish washer	7.1	13.5	26.5
Waste disposal	10.5	13.6	25.5
Television	89.4	106.6	141.2

[1] Statistical issues of Merchandising Week, EEI.

TABLE 3.3

Approximate Wattage Rating and Estimated Annual Kilowatt-Hour Consumption of Electrical Appliances Under Normal Use—1969

Appliance	Average Wattage	Estimated KWH Consumed Annually
Air Conditioner (window)	1,566	1,389
Bed Covering	177	147
Broiler	1,436	100
Carving Knife	92	8
Clock	2	17
Clothes Dryer	4,856	993
Coffee Maker	894	106
Cooker (eggs)	516	14
Deep Fat Fryer	1,448	83
Dehumidifier	257	377
Dishwasher	1,201	363
Fan (attic)	370	291
Fan (circulating)	88	43
Fan (furnace)	292	394
Fan (roll-about)	171	138
Fan (window)	200	170
Floor Polisher	305	15
Food Blender	386	15
Food Freezer (15 cu ft)	341	1,195
Food Freezer (Frostless 15 cu ft)	440	1,761
Food Mixer	127	13
Food Waste Disposer	445	30
Frying Pan	1,196	186
Germicidal Lamp	20	141
Grill (sandwich)	1,161	33
Hair Dryer	381	14
Heat Lamp (infrared)	250	13
Heat Pump	11,848	16,003
Heater (radiant)	1,322	176
Heating Pad	65	10
Hot Plate	1,257	90
Humidifier	117	163
Iron (hand)	1,088	144
Iron (mangle)	1,494	158
Oil Burner or Stoker	266	410
Radio	71	86
Radio-Phonograph	109	109
Range	12,207	1,175
Refrigerator (12 cu ft)	241	728
Refrigerator (Frostless 12 cu ft)	321	1,217
Refrigerator-Freezer (14 cu ft)	326	1,137
Refrigerator-Freezer (Frostless 14 cu ft)	615	1,829
Roaster	1,333	205
Sewing Macine	75	11
Shaver	14	18
Sun Lamp	279	16
Television (B&W)	237	362
Television (Color)	332	502
Toaster	1,146	39
Tooth Brush	7	5
Vacuum Cleaner	630	46
Vibrator	40	2
Waffle Iron	1,116	22
Washing Machine (Automatic)	512	103
Washing Machine (Non-automatic)	286	76
Water Heater (Standard)	2,475	4,219
Water Heater (Quick Recovery)	4,474	4,811
Water Pump	460	231

Source: Edison Electric Institute.

consumption of electrical appliances under normal use.

Transportation

The Electric Car

Public concern over urban air pollution has given a tremendous impetus in recent years to development of a non-air-polluting motor vehicle. Development of an electric power source capable of approaching the performance of the internal combustion engine, however, has been frustrated by the lack of an electric energy storage device of sufficient capacity to provide the desirable mileage range and operating speeds. If the electric car is to win the tremendous potential market for the non-air-polluting vehicle, it must prove at least equivalent in conventional performance characteristics and reasonably close in cost to steam-driven, liquid natural gas-fueled, and any redesigned gasoline fueled automobiles. All of these alternatives are receiving intense developmental efforts in many countries of the world. Apparent advantages of electric power over the other types of automotive prime movers include less noise, simpler operation, and less maintenance.

The market for electric automobiles by 1990 is expected to be about 38 million, most of which would be small second or third family cars. Even if only one-half of that expected market were to develop, the annual consumption of electric energy for recharging batteries could reach about 62 million megawatt-hours per year. This estimate is based on the assumption that

electric cars would be driven an average of 6,500 miles per year and that the energy requirement for recharging batteries would average 0.5 kilowatt-hour per mile. This electric load, concentrated mostly in the larger urban areas, would be equivalent to about 1 percent of the total electric energy production in 1990. It would probably have little effect upon peak demands because most of the cars would be in use during normal peak demand periods, and the batteries would be recharged during the night when system demands are low.

Electrified Transport—Railroads

Power requirements for the electric transport category, other than automotive, are estimated to be eight million megawatt-hours in 1990, or a little over 0.1 percent of energy generation in that year. This projection may be low, however, because it is heavily weighted by the fact that the railroads, to a very large extent, have given way to competition for passenger service from airlines and private and commercial automotive carriers. Other influencing factors include the substantial costs that would be involved in constructing power-feeder facilities and modernizing rail beds to permit high-speed passenger and freight traffic. The potential power requirements could be as much as 25 million megawatt-hours, if current interest in electrified transport culminates, during the next two decades, in coordinated action aimed at providing high-speed economical mass transport of both passengers and freight. Of this potential power requirement, five million megawatt-hours can be attributed to urban rapid rail transport and 20 million to electrified long-haul service.

A growing network of high-voltage transmission lines will be needed to serve the new loads which are expected during the next two decades. This need is encouraging joint use studies by utilities and railroads for new rights-of-way which, where feasible, could appreciably reduce rights-of-way costs for all parties. Also being investigated are arrangements whereby electric utilities might build and own catenaries which feed power to the locomotives. Investment costs of these catenaries could be recovered either by a facilities charge added to the normal power rates or by reimbursements for joint use of the railroad's rights-of-way for the transmission lines.

Some authorities feel that the Nation could best be served by concentrating long-haul service on about 20,000 miles of double track routes which by 1990 would have a traffic density of 20 million tons annually per mile of track. If it is assumed that 25 kilowatt-hours are required for 1,000 gross ton miles of haul, the annual power requirement for such a network of lines would be 20 million megawatt-hours, or 0.3 percent of total generation. The electric locomotive is expected to supplement, not displace, the diesel engine. Electrified trunk lines are envisaged to link the eastern metropolitan areas from Miami to Boston, connect the far western centers from Seattle to Los Angeles, and provide a few transcontinental lines through the major inland cities.

Maintenance costs of electric locomotives promise to be only a third of those of diesel locomotives and they also offer higher horsepower capabilities, shorter turnabout times, and practically noiseless and pollution-free operation.

Cooperative efforts underway among the utilities, railroads, and government officials may produce some reasonable and workable solution to the electrification problems. The recently created National Railroad Passenger Corporation (Amtrak) is expected to provide overall leadership in the development of newer and better methods of passenger transportation.

Rapid Transit

Progress in the expansion of electrified transport within metropolitan areas is much more advanced than that of long-haul railroad systems. In 1971 there were several electrified rapid transit systems—New York City, Chicago, Boston, Cleveland, Philadelphia, Camden-Philadelphia, and Trans-Hudson. These systems have over 1,200 miles of track and consume about 3 million megawatt-hours of electric energy annually.

By 1980, rail rapid transit systems are expected to be in service in the San Francisco Bay area, Washington, D.C., Atlanta, Baltimore, and Pittsburgh. By 1990, St. Louis, Los Angeles, Seattle, Miami, and Minneapolis-St. Paul—and possibly Detroit, Buffalo, and Denver—may have systems in service. It is estimated that by 1990 about seven million megawatt-hours annually will be required to supply the electric energy requirements of metropolitan rail rapid transit systems.

Outdoor Lighting

Improved outdoor lighting is generally recognized as being both desirable and important in improving the quality of life but the Nation has only begun to consider large-scale outdoor lighting as an amenity of urban living. Studies have shown that increased illumination levels of highways reduce automobile accidents, that increased lighting in downtown commercial areas attracts more customers, and that properly lighted streets discourage crime. In 1967, there were 3.7 million miles of streets and roads in the United States, of which about 0.5 million miles were in urban areas. Even in those areas most of the lighting was by low-power obsolete incandescent lamps.

In addition to residential street lighting and outdoor parking area lighting, the potential outdoor lighting market also includes the 3.2 million miles of streets and roads in rural areas, some of which are lighted only at major intersections and village centers. Additional lighting of such streets and roads can be expected as an aid in reducing the hazards of night driving.

Commercial areas and suburban shopping centers provide another large potential for outdoor lighting. It has been estimated that in 1968 there were 3.5 billion square feet of hard-top parking areas at commercial centers. Some of these areas are illuminated to levels as high as eight foot-candles. Since there appears to be no abatement in the growth of urban sprawl and the continuing need for greater downtown parking facilities, commercial center lighting requirements are expected to increase substantially. Other opportunities for additional outdoor lighting are associated with ornamental lighting of public and commercial buildings, lighting for security, lighting of off-street areas in public parks and play areas, and private commercial and residential properties.

Need for Load Projections

A rate of growth which characterizes the industry as a whole may be inadequate as a guide to what can happen to any one system or group of systems. National averages have value for statistical purposes, but they fail to recognize differences among individual systems. For this reason, the statistical material presented in this chapter was developed largely on a utility service area basis and aggregated into regional and national figures.

The enormous increase in demand reflected in the estimates presents a challenge to the electric power industry. During the near future many decisions will be required concerning when, where, and how to provide a million megawatts of new generating capacity, several hundred new plant sites, thousands of miles of EVH transmission, and several thousand major substations. Decisions which determine the immediate and future actions of the Nation's electric supply systems are based on a series of intermediate and long-term load projections by the 3,480 utility systems.

Daily and weekly forecasts are used to schedule the operation of generating units to serve the immediate loads. Short-term projections generally covering 12 to 18 months, are used primarily to establish maintenance schedules, plan interchanges of power, and make final decisions with respect to fuel purchases. Medium range projections are perhaps the most important and receive the most attention because of the serious consequences of error. Normally they include forecasts for about 10 years and serve as the basis for investment decisions relating to new generation, transmission, and distribution facilities. Long-range projections extending beyond 10 years do not have to be precise but should be accurate enough to serve as reasonable planning guides in identifying potential problems, indicating the magnitude of system growth, and providing a basis for long-range activities such as site acquisitions.

Accurate projections enable management to plan generation and transmission facilities in proper relationship to the time of need. Overestimating future load requirements can result in wasteful investments in excess capacity. Underestimating future requirements can lead to brown outs, service interruptions caused by overloading existing facilities, and costly stop-gap expedients which increase the cost of service. Penalities for errors are paid ultimately by utility customers in the form of higher rates, unreliable service, or both.

System load forecasting is a highly empirical process, differing among systems both in degree of sophistication and in the influence attributed

to factors affecting load growth. Some of the smaller electric systems rely generally upon simple extrapolations of historical growth while larger systems give consideration to weather, service area population growth, income, region economic trends, and other factors. Sometimes load projections are determined by complex computer-oriented correlations. Whatever method is used, the projections are based on specific assumptions that affect the accuracy of the results. The need for realistic assumptions for projecting loads becomes more critical with the increase in number and complexity of the involved socio-political factors in determining growth rates. At the same time, establishing realistic assumptions becomes more difficult. For example, as weather-sensitive loads such as electric heating and air conditioning comprise a greater portion of the total load, the need for better methods of quantifying weather effects becomes more critical. Also, environmental considerations, longer lead time required by equipment manufacturers, and unforeseen problems, such as strikes, have extended the period for which reliable projections are needed. It is not uncommon for the decision to install a generating unit at a certain site to precede the actual commitment of funds to equipment manufacturers by three to five years and the actual use on the system by as much as ten years or more. When projects are formally contested, lead times may be extended considerably.

In recognition of the importance of accurate load forecasting, the FPC created an Advisory Committee on Load Forecasting Methodology, to survey current techniques of load forecasting and to explore possible new avenues which might lead to better forecasts. The Committee was of the opinion that some of the econometric techniques developed outside the utility industry might be adaptable to electric utility needs, and was optimistic that more accurate forecasts would eventually evolve out of the variety of techniques now in use or proposed. Computers are expected to be particularly helpful in handling huge masses of data covering system load characteristics, meteorological phenomena, and service area, regional, and national economic trends. The Committee concluded, however, that no single method or group of methods currently in use by the industry alone can assure success in load forecasting and that judgment based on intimate knowledge of the service area is an indispensable element in any load forecast. The Committee's report is reproduced in part IV of this survey.

National and Regional Projections

In developing projections for use in this survey, the Federal Power Commission staff developed load projections for 1980 and 1990. These projections were submitted to the Federal Power Commission's six Regional Advisory Committees for review and modification. Some of the Committees developed their own projections independently. Other Committees adopted the staff-developed projections with revisions. Finally, each Regional Advisory Committee reached a consensus on a projection of the magnitude of the loads which the systems of its region should be prepared to serve during the next two decades. A summation of the regional projections provided the national projection.

In projecting future power requirements to 1990 it was assumed that during the period to 1990 the Nation would continue to enjoy a high level of economic activity, technological improvements in the electric utility industry would continue, a somewhat smaller proportion of national resources would be channeled to military purposes than during the late 1960's, no disruptive epidemic or similar catastrophe would occur, and the Nation would continue to use electricity as an increasing portion of total energy consumption. It was assumed, also, that wholly new technological and social concepts, some of which are discussed earlier in this chapter, would develop at a somewhat accelerated pace. The effects of these changes were considered as a group, however, without any attempt to isolate the effects of foreseeable load-building or load-deterring potentials into separable items.

The Federal Power Commission staff made studies of estimated residential use of electric energy to 1990 based on nationwide historical data for the period 1950 to 1965 and several important demand determinants. One study was based on estimated national population, two levels of income, and two price ratios of electricity to natural gas as the demand determinants. A companion study was based upon the estimated nationwide number and average sizes of

households rather than population and the same two levels of income and price ratios of electricity to natural gas. As a further check on the Regional Advisory Committee projections, similar studies of estimated total electric energy requirements to 1990 were made by the FPC staff during 1969–71, using Gross National Product (GNP) plus the same demand determinants used in the residential requirements studies. A comparison of the range of results of those studies and the projections of the Regional Advisory Committees is shown in table 3.4.

Gross National Product—the value of all the goods and services produced in the United States—can be used as one general indicator of levels of national energy requirements, including electric power requirements. Between 1950 and 1965, GNP, expressed in 1958 dollars, increased from 355.3 billion dollars to 617.8 billion dollars, an average rate of growth of 3.7 percent. In the period 1965–1970 the GNP increased in constant dollars at an average annual rate of about 3.2 percent. Historical and projected increases in GNP and production of electricity are shown graphically on figure 3.5. The present projections of electric energy requirements are based on the assumption that the GNP will continue to grow at an average annual rate of about 4 percent during the next two decades.

TABLE 3.4

Comparison of Staff Econometric Study Results and Regional Advisory Committee Projections for Residential and Total Electric Utility Energy Requirements—1980–1990

[Million Megawatt-Hours]

	Actual	Estimated	
	1970	1980	1990
Residential Requirements			
Staff Studies......	[1] 380	678–837	1,392–1,850
Regional Advisory Committees...........		755	1,409
Total Energy Requirements			
Staff Studies......	1,530	2,775–3,210	5,025–6,325
Regional Advisory Committees...........		3,075	5,828

[1] For year 1969.

GROWTH OF ELECTRICITY PRODUCTION AND GROSS NATIONAL PRODUCT
1929 - 1990

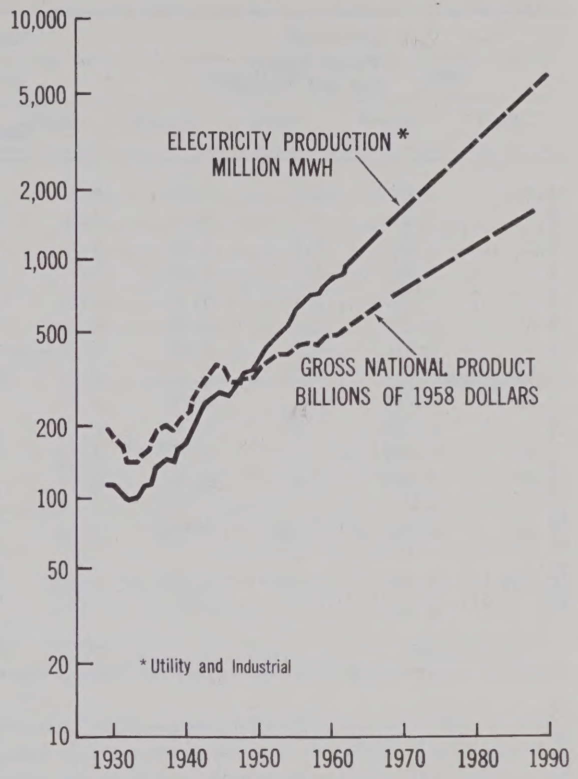

Figure 3.5

Projections of Electric Energy Requirements and Peak Demands to 1990

In 1965 electric utilities in the contiguous United States produced over one billion megawatt-hours of electric energy. By 1980 national electric energy requirements are expected, subject to a range of values such as those indicated in table 3.4, to be about three billion megawatt-hours and by 1990 to be almost six billion megawatt-hours. These estimates represent average annual increases of about 7.4 percent during the 1965–1980 period and about 6.6 percent during the period from 1980 to 1990. During the 1965–70 period the average annual energy growth was 7.7 percent. The sum of regional peak loads is expected to increase from 188,400 megawatts in 1965, to about 554,000 megawatts in 1980, and 1,050,000 megawatts in 1990.

Table 3.5 shows the actual 1970 as well as projected 1980 and 1990 electric utility energy requirements and peak demands for each Power

TABLE 3.5

Electric Utility Energy Requirements and Peak Loads by Power Supply Areas and Regions

[Energy in Million MWh; Peaks in Thousand MW]

Power Supply Area and Region	Actual		Estimated			
	1970		1980		1990	
	Energy	Peak	Energy	Peak	Energy	Peak
1	5.6	1.0	9.0	1.7	15.0	2.8
2	56.0	10.8	102.0	20.4	194.8	38.5
3	46.2	7.8	74.9	12.6	122.2	20.6
4	51.2	10.1	85.1	16.7	147.2	28.6
5	118.7	21.2	218.8	39.3	388.4	69.3
6	13.0	2.9	25.5	6.0	47.1	10.9
Northeast	290.7	52.9	515.3	92.8	914.7	164.7
7	32.9	5.4	52.6	8.6	88.9	14.6
8	15.3	2.6	27.3	5.0	48.5	8.1
9	63.0	4.7	131.1	20.6	230.0	36.7
10	18.4	2.8	32.5	5.3	57.7	9.4
11	54.8	9.5	102.0	17.6	181.0	30.6
12	66.3	12.3	123.0	22.0	233.2	41.4
19	9.4	1.8	18.1	3.5	38.1	7.5
East Central	260.1	44.0	486.6	81.9	877.4	148.0
18	25.4	4.9	57.4	11.2	114.2	21.8
20	94.4	16.8	185.6	33.6	253.2	47.0
21	67.5	12.0	143.6	24.6	313.9	53.3
22	31.5	6.1	67.9	12.9	126.9	24.0
23	35.5	6.9	66.2	12.2	137.8	25.3
24	50.2	9.9	115.5	22.0	258.6	50.3
Southeast	304.5	52.9	636.2	110.0	1,204.6	211.9
13	26.1	4.6	50.5	8.5	91.3	15.3
14	50.3	10.1	105.0	19.8	195.0	37.0
15	19.5	4.4	43.8	9.7	85.1	18.8
16	24.7	4.6	52.8	9.2	105.0	18.4
17 [1]	18.4	3.8	38.1	7.2	74.6	13.1
40	22.9	4.3	44.3	8.1	79.6	14.0
26	4.3	0.7	8.4	1.8	16.1	3.4
27	4.9	0.9	9.5	1.9	18.3	3.7
28	9.4	2.3	18.1	4.4	33.3	8.1
West Central	180.5	35.7	370.5	68.9	698.3	128.6
25	35.1	7.1	78.4	16.4	152.3	31.5
29	7.7	1.8	14.3	3.2	25.6	5.8
33	25.2	5.9	60.1	13.8	116.3	26.6
34 [1]	20.2	4.5	40.6	8.9	77.0	16.4
35	22.2	4.0	64.5	11.2	141.3	24.2
37	38.8	8.4	82.0	18.0	168.0	36.2
38	45.8	9.0	102.7	19.7	219.9	41.5
South Central	195.0	40.6	442.6	91.0	900.4	181.8

TABLE 3.5—Continued

Electric Utility Energy Requirements and Peak Loads by Power Supply Areas and Regions

[Energy in Million MWh; Peaks in Thousand MW]

Power Supply Area and Region	Actual		Estimated			
	1970		1980		1990	
	Energy	Peak	Energy	Peak	Energy	Peak
30	9.7	1.4	15.7	2.6	28.4	4.7
31	4.0	0.6	9.4	1.6	18.8	3.2
32	12.1	2.1	23.4	4.2	45.3	8.0
36	8.6	1.6	18.2	3.5	33.8	6.4
39	5.5	1.0	11.5	2.2	21.6	4.1
41	15.7	2.9	31.4	5.7	63.2	11.5
42	13.2	2.2	18.1	3.0	23.0	3.8
43	33.8	5.9	61.9	11.8	118.7	22.6
44 & 45	45.0	7.6	96.8	17.4	183.0	32.9
46	58.6	10.5	136.0	24.1	291.0	51.6
47	75.5	13.4	151.0	27.7	298.0	55.0
48	22.1	4.6	50.3	9.6	108.0	20.6
West	303.8	49.6	623.7	109.4	1,232.8	216.4
Total Utility	1,534.6	275.7	3,074.9	554.0	5,828.2	1,051.4
Industrial	107.7	....	127.0	....	150.0	....

[1] A portion of PSA 17 was transferred to PSA 34, effective January 1, 1969. The loads shown for 1965 have been adjusted to reflect the current boundaries as shown in figure 3.6.

Note: Each power supply area peak represents the sum of individual utility system peaks occurring in the same month. The month of peak varies among power supply areas. Each regional peak represents the sum of individual utility system peaks occurring in the same month and is not necessarily equal to the sum of its power supply area peaks. The peak shown for the 48 contiguous States is the sum of the regional peaks shown and is somewhat higher than the instantaneous peak.

Supply Area and Regional Advisory Committee region. Figure 3.6 shows the Power Supply Areas and regions.

Figure 3.7 shows actual and estimated electric utility energy requirements for the period 1880 to 1990. The estimates for the period 1970 to 1990 are shown as a single line on Curve A, but in the expanded portion (Curve B) the estimates are shown as a ridge line, bordered on either side by shading to reflect the range in requirements resulting from the several econometric studies by the Commission's staff. For the selected Point P shown on expanded Curve B of figure 3.7 the electric energy requirement for 1980 would be about 3.0 billion megawatt-hours. By varying the combinations of assumptions considered by the staff, Point P could be moved to the right or left to indicate that this amount of electric energy consumption would take place at an earlier or later date than 1980. Also, the end points of a vertical line in the shaded area through the Point P would indicate that in the year 1980 the energy requirements might be greater or less than 3.0 billion megawatt-hours. If other assumptions were used, the shaded area might become an even wider band.

Recognizing that available energy resources are finite and that the ultimate per capita use of electric energy has an upper limit, it is inevitable that the rate of growth in electric energy consumption eventually will decrease. There are too many imponderables, however, to predict the timing and magnitude of a much slower growth rate. For the period to 1990, the potential for increased use of electric energy appears ample to maintain a growth rate that will result in approximately doubling the use every ten years. If there is substantial realization of this potential, then the projection of electric energy production to 1990, as shown in figure 3.7, will prove to be too low.

NATIONAL POWER SURVEY REGIONS AND POWER SUPPLY AREAS

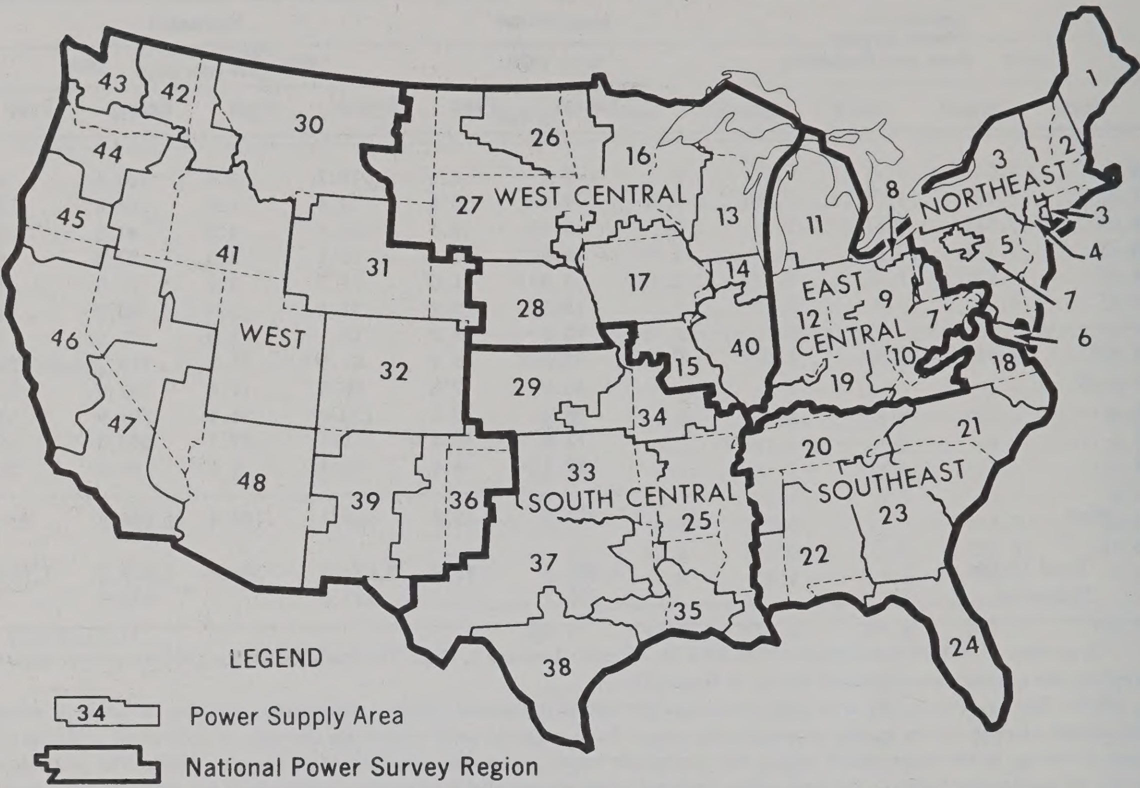

Figure 3.6

The Commission's Order No. 383–2, Statement of Policy, issued April 10, 1970, established a system for the voluntary reporting by regional electric reliability councils of current and projected system data for all components of the electric power industry. Reports were filed as of September 1, 1970, and April 1, 1971, and subsequent reports are to be filed by April 1 of each year. Each will include estimates of future loads for a period of ten years. Such projections should provide the primary basis for definitive planning of new facilities.

Except for the West Region, the ten-year projections of future loads included in the first two reports of the councils were higher than the corresponding estimates made in 1968 and 1969 by the Regional Advisory Committees and included in this chapter. Projections for the Northeast and Southeast Regions were significantly higher. On a national basis, the April 1971 estimates were about 8 percent higher than those prepared for the Regional Advisory Committee reports, thus illustrating the importance of frequent review.

Energy Requirements by Class of Use

Industrial, residential, and commercial loads account for more than 80 percent of the total electric energy requirements of the contiguous United States, and projections of energy requirements to 1990 for the various categories of use indicate little change in their relative proportions.

Historical and projected annual electric energy requirements by class of use are shown in table 3.6 and the projected rates of increase are given in table 3.7. Industry, the largest class of users of electric energy in the United States, is expected to require annually, by 1990, 2,386 million megawatt-hours of energy from electric

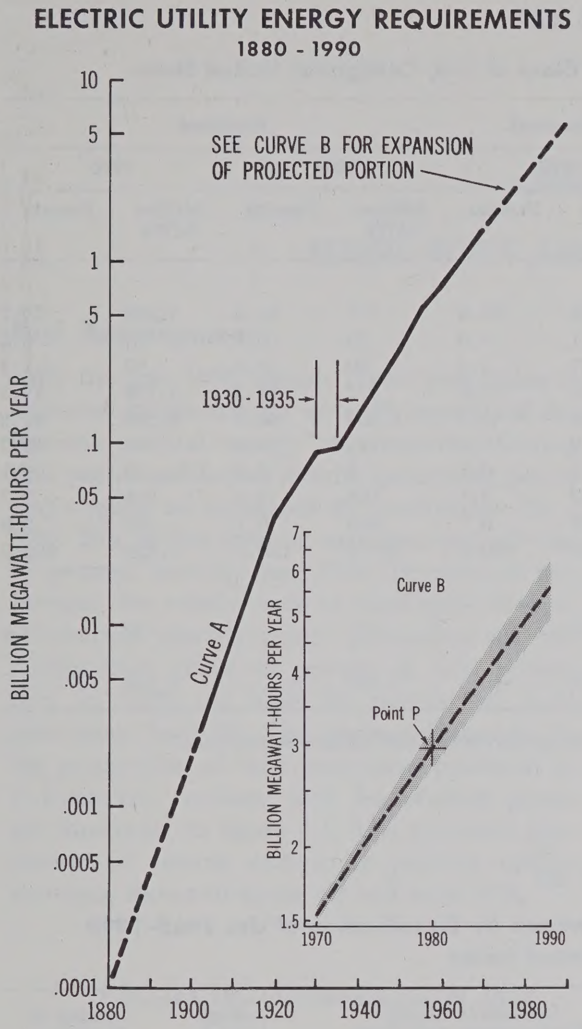

Figure 3.7

utility systems plus 150 million megawatt-hours from in-plant generation. Through 1990, the industrial category is expected to account for about 40 percent of total United States electrical energy consumption. The estimated increase during this period represents an average annual growth rate of about 7 percent.

Residential nonfarm use, representing about 25 percent of the total requirements, is the second largest classification. This use is expected to increase from 254 million megawatt-hours in 1965 to 1,409 million megawatt-hours in 1990. If 60 percent of electric energy consumption on farms is assumed to be farm residential, then total residential electric energy consumption in 1965 and 1990 would be 270 and 1,467 million megawatt-hours, respectively. On this basis, in 1965, when there were 57.1 million households in the contiguous States including farm households, the average annual electric energy consumption per household was 4,700 kilowatt-hours. In 1990, it is expected that the number of households, farm and nonfarm, will increase to 92.2 million, and annual electric energy consumption per household will be about 15,900 kilowatt-hours.

TABLE 3.6

Annual Electric Energy Requirements by Class of Use, Contiguous United States

Category of Use	Historical 1965		Projected 1980		1990	
	Million MWh	Percent	Million MWh	Percent	Million MWh	Percent
Electric Utilities						
Residential (Nonfarm)	254	24.0	755	24.6	1,409	24.2
Irrigation & Drainage Pumping	11	1.0	23	0.7	34	0.6
Other Farm [1]	27	2.5	60	2.0	97	1.7
Commercial	190	18.0	577	18.7	1,138	19.5
Industrial	436	41.3	1,257	40.9	2,386	40.9
Street & Highway Lighting	9	0.9	23	0.8	40	0.7
Electrified Transport [2]	5	0.5	7	0.2	8	0.1
Other Uses	32	3.1	105	3.4	214	3.7
Losses & Unaccounted For	92	8.7	268	8.7	502	8.6
Total Utility	1,056	100.0	3,075	100.0	5,828	100.0
Industrial Establishments						
In-Plant Generation [3]	102	....	127	....	150	....
Total	1,158	....	3,202	....	5,978	....

[1] Includes residential use on farms; other residential uses in rural areas included under "Residential."
[2] Excludes electrification of automobiles.
[3] Excludes industry sales to electric utilities.

TABLE 3.7

Projected Increases in Electric Energy Requirements by Classification of Use 1965–1990 Contiguous United States

Class of Use	Increase in Energy Requirements 1965–1990 (Million MWh)	Percent	Average Annual Rate of Growth (%)	Number of Years to Double Consumption
Electric Utilities				
Residential (Nonfarm)	1,155	454	7.08	10
Irrigation and Drainage Pumping	23	209	4.62	15
Other Farm [1]	70	259	5.24	14
Commercial	948	498	7.41	10
Industrial	1,950	447	7.04	10
Street and Highway Lighting	31	344	6.14	12
Electrified Transport [2]	3	60	1.90	37
Other Uses	182	569	7.90	9
Losses and Unaccounted For	410	446	7.04	10
Total Utility	4,772	452	7.06	10
Industrial Establishments				
In-Plant Generation [3]	48	47.1	1.55	45
Total	4,820	416.2	....	....

[1] Includes residential use on farms; other residential uses in rural areas included under "Residential."
[2] Excludes electrification of automobiles.
[3] Excludes industry sales to electric utilities.

CHAPTER 4

FOSSIL FUELS AND FUEL TRANSPORT

Fuel Requirements

By the year 1990, electric power generation is expected to account for over 40 percent of the Nation's annual energy requirements. During that year, fossil-fueled electric generating plants may require an estimated 25 quadrillion (25 x 10^{15}) Btu in the form of coal, gas, and oil—an 87 percent increase over 1970. In spite of this increase, the relative role of fossil fuels in overall thermal electric power generation will diminish from about 82 percent of total generation in 1970, to only 44 percent of total generation by 1990. The projected changes in the proportions of total generation produced in hydroelectric, nuclear, and fossil-fueled plants are illustrated in figure 4.1. The projected generation of electric energy by primary energy sources is shown in figure 4.2 and table 18.8.

PROJECTED GENERATION MIX

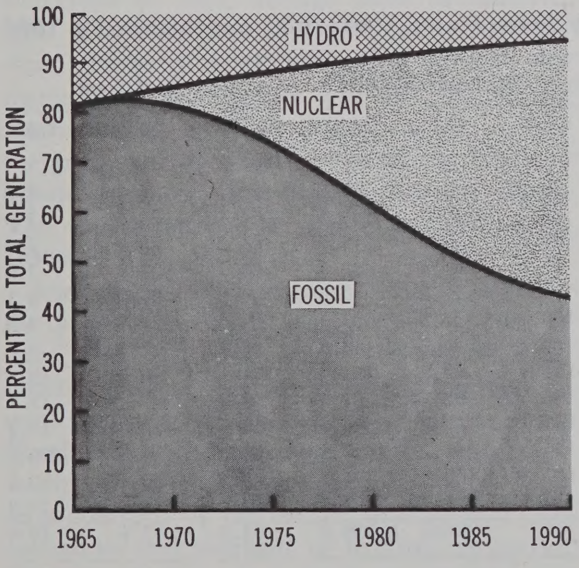

Figure 4.1

ESTIMATED ANNUAL ELECTRIC UTILITY GENERATION BY PRIMARY ENERGY SOURCES

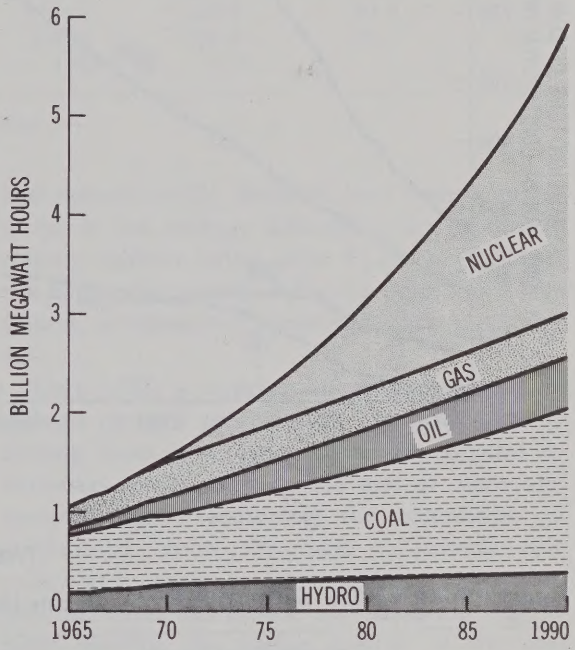

Figure 4.2

The rapidly growing primary energy requirements of the electric power industry will place ever-increasing demands on both domestic and foreign fuel resources. During the 21-year period 1970–1990, the industry is expected to burn 10 billion tons of coal, 80 trillion cubic feet of gas, and more than 13 billion barrels of oil. Annual consumption of fossil fuels for electric power generation for the 10-year period 1961–1970 and projected consumption for selected years to 1990 are shown in figure 4.3 and table 4.1. The outlook by Regions is summarized in the final portion of this chapter.

ESTIMATED ANNUAL FOSSIL FUEL REQUIREMENTS FOR ELECTRIC UTILITY GENERATION

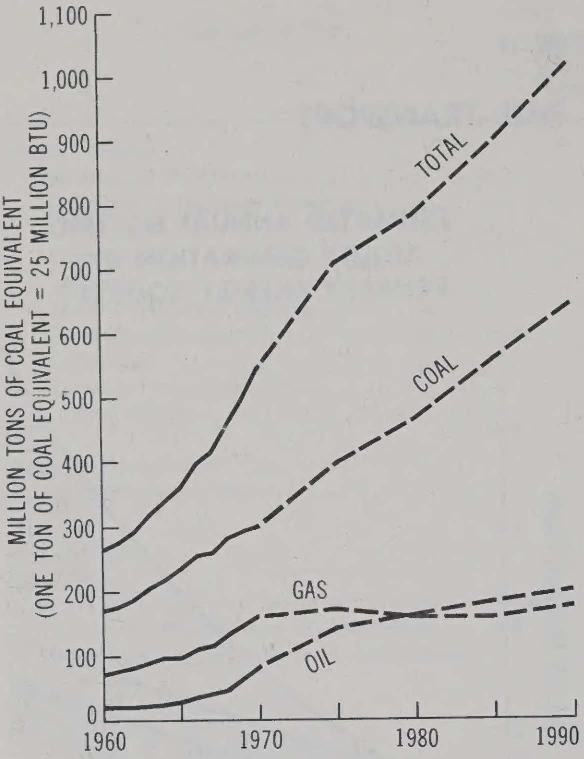

Figure 4.3

Coal

Coal is the most abundant indigenous fossil fuel and currently provides the primary energy for about 56 percent of fossil-fueled electric generation, or slightly less than one-half of total electric generation. In the ten years from 1961 to 1970, electric utility consumption of coal increased steadily, as shown in table 4.2.

The bulk of the coal currently consumed by electric utilities is bituminous. Only about 2 million tons of anthracite and about 3.5 million tons of lignite are consumed each year for power generation. The major attractions of bituminous coal to the utilities have been its relative abundance and the coal industry's ability, until recently, to maintain price stability despite inflation. During the five-year period 1961–1965, the average mine price of bituminous coal and lignite actually declined. This decline, together with a declining trend in the average price of railway coal transport—primarily an outgrowth of innovations in transport and handling technology—led to decreases in the "as burned" price of coal to electric utilities. Electric utility use of coal increased by an average of about 13 million tons per year while the combined requirements for all other needs at home and for export remained nearly constant. Consequently, the electric utility industry's role as the largest

TABLE 4.1

Annual Consumption of Fossil Fuels by Electric Utility Power Plants, 1961–1970, and Projected to 1990

Year	Conventional Units [1]			10^6 Tons of Coal Equivalent [2]				Percent of Total		
	Coal	Gas	Oil	Coal	Gas	Oil	Total	Coal	Gas	Oil
1961	182.1	1,825.1	85.7	174.8	76.3	21.6	272.7	64.1	28.0	7.9
1962	193.2	1,966.0	85.8	185.4	82.3	21.7	289.4	64.1	28.4	7.5
1963	211.3	2,144.5	93.3	202.6	89.6	23.5	315.7	64.2	28.4	7.4
1964	225.4	2,322.9	101.1	215.7	97.0	25.6	338.3	63.7	28.7	7.6
1965	244.8	2,321.1	115.2	233.5	97.0	29.0	359.5	64.9	27.0	8.1
1966	266.5	2,609.9	140.9	253.0	109.2	35.5	397.7	63.6	27.5	8.9
1967	274.2	2,746.4	161.3	258.3	114.7	40.6	413.6	62.5	27.7	9.8
1968	297.8	3,147.9	188.6	280.5	131.4	47.5	459.4	61.1	28.6	10.3
1969	310.3	3,486.4	250.9	292.3	145.5	63.2	501.0	58.4	29.0	12.6
1970	322	3,894	332	300.2	161.7	82.8	544.7	55.1	29.7	15.2
1975	425	4,110	565	396.1	170.2	141.2	707.5	56.0	24.0	20.0
1980	500	3,800	640	464.0	157.3	160.0	781.3	59.4	20.1	20.5
1985	600	3,800	725	554.4	157.3	181.3	893.0	62.1	17.6	20.3
1990	700	4,200	800	644.0	174.0	200.0	1,018.0	63.3	17.1	19.6

[1] In millions of tons of coal, millions of barrels of oil, and millions Mcf of gas.
[2] A ton of coal equivalent was assumed as containing 25 million Btu.

TABLE 4.2

Total Domestic and Utility Consumption of Coal,[1] 1961–1970

Year	Total Domestic Production in 10^6 Tons	Total Domestic Consumption in 10^6 Tons	Electric Utility Consumption in 10^6 Tons	Utility Consumption as Percent of Total Consumption	Average Cost to Utilities "as Burned" in Cents Per 10^6 Btu
1961	420.4	390.3	182.1	46.7	25.8
1962	439.0	402.8	193.2	48.0	25.6
1963	477.2	423.3	211.3	49.9	25.0
1964	504.2	445.5	225.4	50.6	24.6
1965	527.0	472.1	244.8	51.9	24.4
1966	546.8	497.7	266.5	53.5	24.7
1967	564.9	491.1	274.2	55.8	25.2
1968	556.7	509.0	297.8	58.5	25.5
1969	571.0	516.9	310.3	60.0	26.6
1970	605.8	519.0	322.0	62.0	N.A.
70/61 Ratio	1.44	1.33	1.77		

[1] All types of coal, including bituminous, lignite and anthracite.

single domestic consumer of coal increased steadily until, in 1963, one-half of the total coal consumed in the United States was for electric power generation. This proportion continued to grow and reached 62 percent in 1970.

In some instances, notably in the West, electric utilities have acquired and operate their own coal mines. The coal mining industry, and especially the leading producers, have recognized the opportunity in the electric utility market and responded to the needs of the electric utility industry. Within the relatively short period 1959 to 1967, average labor productivity grew from 12.22 tons to 19.17 tons per man-day—an increase of nearly 57 percent. Most of this increase in productivity was due to greater mechanization of all mining operations and to the growing proportion of bituminous coal and lignite produced from strip and auger mines. This is illustrated by the figures in table 4.3 for 1959 and 1967.

Another factor which contributed to lowering the price of coal was the growing number of large mines (output of 500,000 tons or more annually) and an increase in the proportion of total coal output produced from these mines. Development of these more efficient mines was facilitated, in part, by the negotiation of long-term contracts by the electric utilities with coal companies and railroads or barging companies. These contracts assured the financing necessary for the development of more efficient mining and transportation facilities, and were a major factor in the average delivered price of coal to electric utilities being from $1.75 to $2.00 per ton below the average delivered price to all consumers, as illustrated by the costs shown in table 4.4.

Since 1965, a number of developments have exerted upward pressures on the price of coal. Among these developments were the general inflationary trend affecting the cost of labor and materials; laws requiring the restoration of strip-mined lands; the need to prevent acid mine-water drainage into rivers, lakes, and ground water reservoirs; air pollution regulations limiting the sulfur content of the coal used; and more stringent health and safety regulations for the operation of coal mines.

Because of growing competition from nuclear generating units and because of uncertainties about the quality of coal which would be demanded by electric utilities to meet air quality control regulations, there has been a slowdown in the development of new coal mines during the past several years. In 1969 and during the first half of 1970, the demand for coal outpaced supply. Coal stocks at many power plants were seriously depleted and the price of coal increased substantially. Prices for other fossil fuels also increased.

The coal supply position is expected to improve in the years ahead and, partly as a result of further progress in coal mining technology, it

TABLE 4.3

Coal Production from Strip and Auger Mines

Bituminous Coal and Lignite	Output in Million Tons 1959	Output in Million Tons 1967	Percent Increase, 1967 over 1959
Strip mined	121.0	185.7	53.5
Auger mined	7.6	16.0	110.5
Total	128.6	201.7	56.8
Total bituminous coal and lignite mined	412.0	552.6	34.1
Strip and auger mined as percent of total mined	31.2	36.8	....

is expected that coal will maintain its competitive position relative to other fossil fuels (see figure 4.4).

Coal Resources

The United States is well-endowed with coal resources. As shown in table 4.5, resources of bituminous and anthracite coal (in beds 14 or more inches thick), and subbituminous coal and lignite (in beds 2.5 feet or more thick) as of January 1, 1967, were over 1,500 billion tons. This figure includes the coal resources with overburdens of less than 3,000 feet, as determined by mapping and exploration. An additional 1,300 billion tons of coal have been estimated to exist in unmapped and unexplored areas.

It is generally assumed that approximately one-half of the total geological reserve is recoverable. The average recovery from deposits currently being mined by underground methods is between 55 and 60 percent. The recovery rate for strip mines is about 80 percent.

At the 1970 rate of coal output—590 million tons of bituminous coal and lignite and 9 million tons of anthracite—and assuming a 50 percent recovery rate, the estimated coal resources could meet the national demand for centuries. Because of its domestic abundance, widespread geographical distribution, and chemical versatility, coal is destined to play an important role in the energy economy of the United States for many years to come. However, the competitive position of coal in the electric utility market is highly affected by the geographical distribution of the deposits in relation to major electric load centers and by the physical and chemical characteristics of those deposits. Thus, the trends in consumption of coal for electric generation can be expected to vary from one region to another.

TABLE 4.4

Coal Prices—1965, 1968, and 1969

	Price per Ton 1965	Price per Ton 1968	Price per Ton 1969
Average mine price to all consumers	$4.44	$4.67	$4.77
Average railroad freight charges	3.13	3.01	3.45
Total average delivered price of coal to all consumers	$7.57	$7.68	$8.22
Average delivered price to electric utilities	$5.71	$5.93	$6.22

RELATIVE USE OF COAL, GAS, AND OIL IN PROJECTED FOSSIL-FUELED GENERATION

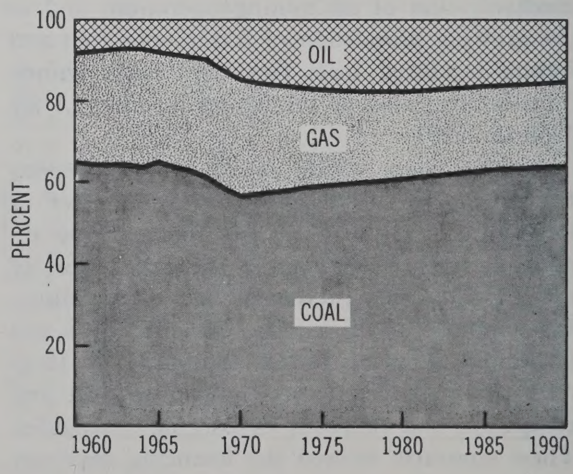

Figure 4.4

TABLE 4.5

Total Estimated Remaining Coal Resources of the United States January 1, 1967

[In Millions of Short Tons] [1]

State	Bituminous Coal	Subbituminous Coal	Lignite	Anthracite and Semi-Anthracite	Total
Alabama	13,518	0	20	0	13,538
Alaska	19,415	110,674	([2])	0	130,089
Arkansas	1,640	0	350	430	2,420
Colorado	62,389	18,248	0	78	80,715
Georgia	18	0	0	0	18
Illinois	139,756	0	0	0	139,756
Indiana	34,779	0	0	0	34,779
Iowa	6,519	0	0	0	6,519
Kansas	18,686	0		0	18,686
Kentucky	65,958	0	0	0	65,958
Maryland	1,172	0	0	0	1,172
Michigan	205	0	0	0	205
Missouri	23,359	0	0	0	23,359
Montana	2,299	131,877	87,525	0	221,701
New Mexico	10,760	50,715	0	4	61,479
North Carolina	110	0	0	0	110
North Dakota	0	0	350,680	0	350,680
Ohio	41,862	0	0	0	41,862
Oklahoma	3,299	0		0	3,299
Oregon	48	284	0	0	332
Pennsylvania	57,533	0	0	12,117	69,650
South Dakota	0	0	2,031	0	2,031
Tennessee	2,652	0	0	0	2,652
Texas	6,048	0	6,878	0	12,926
Utah	32,100	150	0	0	32,250
Virginia	9,712	0	0	335	10,047
Washington	1,867	4,194	117	5	6,183
West Virginia	102,034	0	0	0	102,034
Wyoming	12,699	108,011	([2])	0	120,710
Other States	618	4,057	46	0	[3] 4,721
Total	671,055	428,210	447,647	12,969	1,559,881

[1] Derived from Department of the Interior, Geological Survey, Open File Report 1968, by Paul Averitt, U.S.G.S.
[2] Small resources of lignite included under subbituminous coal.
[3] Includes Arizona, California, Idaho, Louisiana, Nebraska, and Nevada.

Coal Distribution

Figure 4.5 shows the general distribution of the principal coal resources. This map and table 4.5 show that nearly 70 percent of the total resources of all types of coal are located west of the Mississippi River. Some of the areas, shown as underlain by coal, contain marginal resources which could not be economically recovered under existing mining technology. Low-cost coal-producing areas are considerably more limited than the total coal-bearing areas shown on the map, leaving significant segments of the country without easy access to low-cost coal. For these areas, the energy transport cost, whether by unit-train to load center plants or by high-voltage transmission from mine-mouth plants, becomes too large and effectively diminishes the competitive position of coal. The New England states, New York, New Jersey, the southern regions along the Atlantic Coast, the Gulf states (except for the coastal areas where coal can be barged), and the five westernmost of the contiguous 48 states are the areas most seriously affected by the distance factor. In the West, generally, the cost of transporting energy to population centers is offset by the low cost at

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which coal can be produced in the Mountain states. In California, the problems of licensing nuclear plants in areas of above-average earthquake activity tend to stimulate greater use of fossil fuels, but the use of coal in northern and central California is held back by the great distances from the mines and the shortage of cooling water at sites where air pollution control problems are manageable.

Over 94 percent of the bituminous coal and lignite produced in 1968 came from nine states: West Virginia (26.8 percent); Kentucky (18.6 percent); Pennsylvania (14.0 percent); Illinois (11.5 percent); Ohio (8.9 percent); Virginia (6.8 percent); Indiana (3.4 percent); Alabama (3.0 percent); and Tennessee (1.5 percent). Consequently, the bulk of the utility coal is consumed in these and the nearby states.

Physical Characteristics of Deposits

The cost of mining coal is to a considerable extent determined by the geological characteristics of the coal deposits and associated strata, primarily the thickness and continuity of mineable beds, depth of overburden, and general quality of the host rock. Nearly 90 percent of the United States' coal resources, as determined by mapping and exploration, have an overburden of less than 1,000 feet. An estimated 135 billion tons are in beds less than 100 feet below the surface and thus are suitable for strip mining. Approximately two-thirds of the strippable coal and lignite is located west of the Mississippi.

An estimated 400 billion tons of coal are contained in thick beds lying less than 1,000 feet below the surface. The distribution of this coal is shown in table 4.6. About one-half of the thick coal is recoverable and will undoubtedly provide the bulk of future electric utility coal requirements. In addition, 350 billion tons of coal (one-half recoverable) are contained in beds of intermediate thickness, also at depths of less than 1,000 feet below the surface.[1]

The general abundance of potentially mine-

[1] United States Geological Survey Classification is:

	Thick Beds	*Intermediate Beds*
Bituminous coal and anthracite:	More than 42 in.	28–42 in.
Subbituminous coal and lignite:	More than 10 ft.	5–10 ft.

DISTRIBUTION OF FOSSIL FUEL RESERVES

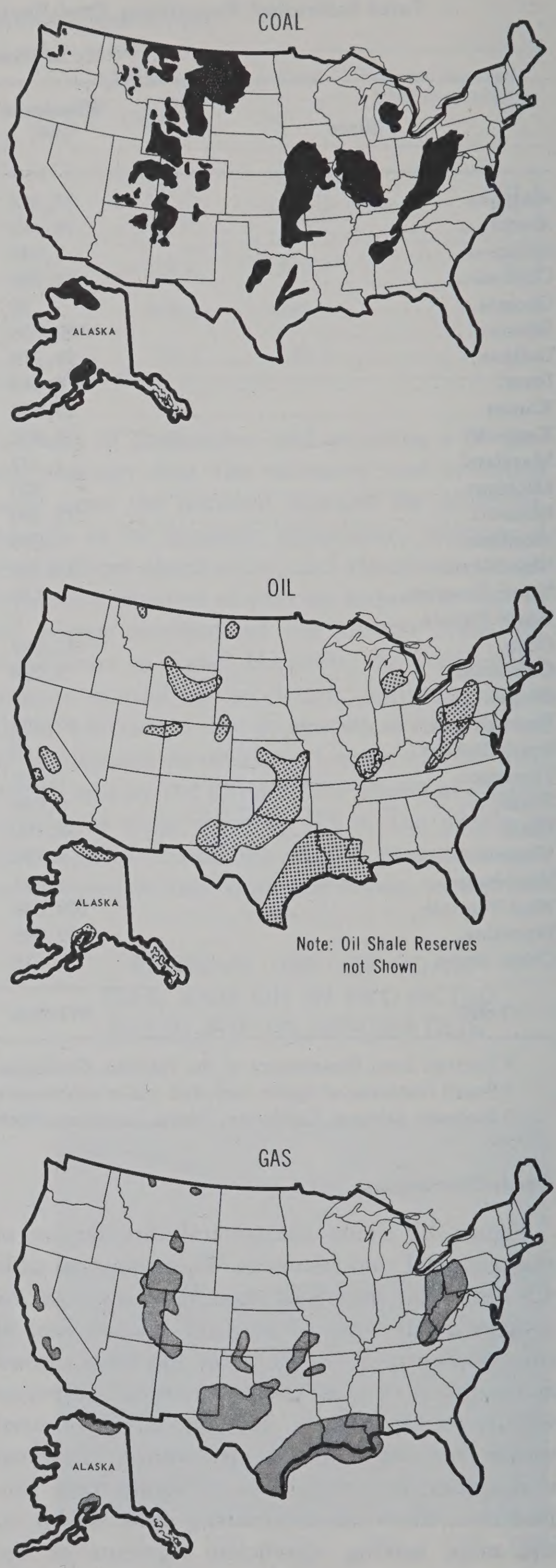

Figure 4.5

TABLE 4.6

Remaining U.S. Coal Resources by Basin or Region, and by Thickness of Beds[1] January 1, 1967

[In Billions of Tons]

Basin or Region	Total Remaining Resources	Resources in Thick Beds,[2] Generally Less Than 1000 Ft Below the Surface	Resources in Thinner Beds Less Than 1000 Feet Below the Surface, and in All Beds 1000–3000 Feet Below the Surface
Northern Appalachian Basin (Pa., Ohio, W. Va., and Md.)	215	58	157
Southern Appalachian Basin (Eastern Ky., Va., Tenn., N.C., Ga., and Ala.)	56	12	44
Michigan Basin	Neg.	Neg.	Neg.
Illinois Basin (Ill., Ind., and Western Ky.)	211	107	104
Western Interior Basin (Iowa, Kans., Mo., Okla., Ark., and Tex.)	67	11	56
Northern Rocky Mountains (N. Dak., S. Dak., Mont., Wyo., and Idaho)	696	152	544
Southern Rocky Mountains (Colo., Utah, Ariz., and N. Mex.)	178	36	142
West Coast (Alaska, Wash., Oreg., and Cal.)	137	24	113
Total	1,560	400	1,160

[1] As determined by mapping and exploration, U.S.G.S. Bul. 1275, "Coal Resources of the U. S."

[2] Includes bituminous coal and anthracite in beds 42 inches or more thick, and subbituminous coal and lignite in beds 10 feet or more thick.

able coal of all grades, including low-sulfur coal, is unquestioned. However, considerations such as recoverability, geographical distribution, competition with coke and export markets, and the deleterious effects on the environment from coal mining operations, have made it increasingly difficult, at least in the eastern part of the country, to secure commitments for adequate supplies of high-quality coal for the life of new, large power plants. In order to improve the competitive outlook, the coal industry will have to invest in an extensive program to extend its knowledge about the distribution of the coal resources and to develop low-sulfur coal reserves for the commercial market.

Chemical Properties and Their Effect on Coal's Competitive Position

The sulfur content of United States' coals ranges from 0.2 to 7.0 percent by weight; the ash content normally ranges from 5 to 20 percent by weight. Ash creates a variety of problems in the operation of electric utility boilers—slagging, abrasion, reduced efficiency, air pollution, and waste disposal. Usually, the higher the ash content, the more intense the problems. These problems can be reduced to acceptable levels through proper design and operation of furnaces, boilers, and particulate emission control equipment.

Sulfur in the coal contributes to corrosion of boilers and to air pollution. While some of the boiler corrosion problems can be controlled by charging limestone or dolomite with the coal, a practical solution for the control of sulfur oxide emissions through treatment of flue gases has yet to be developed, although several proposed methods are currently being tested on an industrial scale. (See chapter 11, Air Pollution). Until effective low-cost devices become commercially available, air pollution regulations to

limit sulfur oxide emissions will generally be met by limiting the sulfur content of fuels burned.

The United States has large resources of low-sulfur coal—coal containing less than 1.5 percent sulfur by weight [2] (see table 4.7). Yet, electric utilities in the eastern United States have experienced difficulty in securing adequate supplies of low-sulfur coal. All of the low-sulfur subbituminous coal and lignite resources, and one-half of the bituminous coal containing less than 1.5 percent sulfur by weight are located west of the Mississippi. In the East, the bulk of the low-sulfur bituminous coal reserves, estimated at 122 billion tons, are located in Appalachia. Three-quarters of that coal (91 billion tons) is metallurgical grade coking coal, mostly in West Virginia (51.5 billion tons) and East Kentucky (23 billion tons).

The low-sulfur, metallurgical grade coking coals are in great demand both here and abroad. Substantial reserves of this coal, therefore, are either dedicated to the metallurgical and export markets or are directly owned by steel companies in the United States. Some low-sulfur coal is also dedicated to electric utility and industrial customers under long-term contracts.

Low-Sulfur Coal for Electric Utilities

The need to control sulfur oxide emissions has created demands for low-sulfur coal as a replacement fuel for existing units, and for new plants. Electric utilities compete with the metallurgical and export markets for available supplies of low-sulfur coal, particularly in the East, and they may have to pay a premium of as much as $3 per ton for such coal.

When low-sulfur coal is substituted for coal with a higher sulfur content in an existing power plant, care must be taken to insure that the total ash content, ash fusion temperature, grindability, and volatility are kept within prescribed limits. Low sulfur coal tends to have higher fly ash electrical resistivity, and thus to reduce the efficiency of electrostatic precipitators. Furthermore, there is an inverse relationship between the sulfur content of United States' coals and their ash-softening (fusion) temperature. Consequently, switching to coal with a lower sulfur content, but with a higher ash fusion temperature, may cause serious heat exchange and slag tapping problems in wet-bottom boilers.

A modern 1,000-megawatt coal-fired unit requires about 2.5 million tons of coal annually during the initial years of base load operation and a total of 35 to 40 million tons of coal for the first 20 years of operation. Considering coal recovery rates, this would require a minimum of 65 to 75 million tons of coal in place to serve the needs of a single 1,000-megawatt unit for the first 20 years of operation.

To achieve low unit-train freight rates, the coal must come from one or two mines. When more mines are involved, some of the principal cost-saving advantages of unit-trains are lost (see Section on Coal Transport). There are very few existing underground coal mines in this country capable of expanding annual output by 2.5 million tons (or even 1.25 million tons where two mines are involved). Given the necessary lead time, some strip mining operations can be expanded substantially. Essentially, however, large, new coal-fired units will require the opening of new coal mines. Coal executives estimate that in order to be economically feasible, a new underground mine, costing from $10 to $12 per annual ton of productive capacity, must have an annual output of at least 1 million tons and sufficient underground reserves to support production for at least 25 years. In order to raise the required investment capital, coal companies would require 20-year firm contracts for the entire output of such new mines. Under those arrangements, utilities can obtain more favorable prices for the coal, such as might be negotiated on a "cost-plus" type of contract.

The number of potential mine sites where economically mineable low-sulfur coal is still available in large blocks, undisturbed by earlier mining operations, neither owned by nor dedicated to the metallurgical and export industries, and near established direct transport routes, is relatively limited. Development of mines at locations which will involve additional railroads and more circuitous transport routes usually results in substantial and, sometimes, dispropor-

[2] The Bureau of Mines classification includes in the low-sulfur coal category only coals with less than 1 percent sulfur by weight. Much of the coal containing 1.1 to 1.5 percent sulfur, however, can be cleaned to meet metallurgical coking coal specifications of less than 1.25 percent sulfur and less than 8 percent ash, assuming that the coal has coking qualities.

TABLE 4.7

Estimated Remaining Coal Reserves of the United States by Type, Sulfur Content, and State, on January 1, 1965 [1]

[Millions of Short Tons]

Coal Type and State	Sulfur Content, %				
	0.7 or Less	0.8–1.0	1.1–1.5	Over 1.5	Total
Bituminous Coal					
Alabama	889.2	1,189.3	5,421.7	6,077.6	13,577.8
Alaska	20,287.4	1,100.0			21,387.4
Arkansas			1,128.4	487.4	1,615.8
Colorado	25,178.3	37,237.2			62,415.5
Georgia		76.0			76.0
Illinois [2]			1,808.0	137,948.0	139,756.0
Indiana	197.5	173.0	3,645.2	30.825.4	34,841.1
Iowa				6,522.5	6,522 5
Kansas			519.9	20,218.1	20,738.0
Kentucky					
West			1,119.6	35,775.8	36,895.4
East	13,639.9	8,491.9	2,286.8	4,996.2	29,414.8
Maryland				1,180.0	1,180.0
Michigan				205.0	205.0
Missouri				78,760.0	78,760.0
Montana	51.2	218.2	205.0	1,630.2	2,104.6
New Mexico	5,212.0	5,474.0			10,686.0
North Carolina				110.0	110.0
Ohio		611.0	369.0	41,044.0	42,024.0
Oklahoma	250.6	772.2	825.0	1,455.0	3,302.8
Oregon		14.0			14.0
Pennsylvania	44.0	1,154.4	7,624.4	49,128.7	57,951.5
Tennessee	3.3	160.9	715.9	959.4	1,839.5
Texas				7,978.0	7,978.0
Utah	8,551.4	13,584.0		5,522.6	27,658.0
Virginia	1,981.5	6,077.5	1,637.1	123.9	9,820.0
Washington	898.9	672.1			1,571.0
West Virginia	20,761.0	26,710.6	21,819.7	33,375.1	102,666.4
Wyoming	6,222.2	6,596.6		1.1	12,819.9
Other States		616.0			616.0
Total	104,168.4	110,928.9	49,125.7	464,324.0	728,547.0
Percent of total	14.3	15.2	6.7	63.8	100.0
Subbituminous Coal [3]					
Total	256,616.3	130,586.3	150.5	1,312.3	388,665.4
Percent of total	66.0	33.6	0.1	0.3	100.0
Lignite [4]					
Total	344,623.6	61,388.5	41,164.5	464.7	447,641.3
Percent of total	77.0	13.7	9.2	0.1	100.0
Anthracite [5]					
Total	14,652.0	96.0		431.8	15,179.8
Percent of total	96.5	0.6		2.9	100.0
Grand total	720,060.3	302,999.7	90,440.7	466,532.8	[6] 1,580,033.5
Percent of total	45.6	19.2	5.7	29.5	100.0

[1] Data is from U. S. Bureau of Mines' Circular 8312 dated 1966 except for Illinois. The table includes coal in seams at least 14 inches thick and less than 3,000 feet deep in explored areas. Approximately one-half of these reserves are considered recoverable.

[2] Data from Illinois State Geological Survey Circular 432 dated 1968. 1966 Data.

[3] Nearly 80 percent in the Rocky Mountain area and most of the remainder in Alaska.

[4] Practically all in North Dakota and Montana.

[5] Over 80 percent in Pennsylvania and most of the remainder in Alaska.

[6] Revised in 1967 by the U. S. Geological Survey to 1,559,875 million tons.

tionate freight cost increases, even though the straight line distance from point of production to point of consumption remains the same.

Declining capacity factors on large coal-fired units, technological innovations, and uncertainties surrounding future air pollution control requirements complicate and increase the risks associated with long-range coal buying, although the larger utility systems have a degree of flexibility enabling them to minimize the penalties of contracts which require acceptance of the full normal output of a mine.

Mine-Mouth Plants

The construction of generating plants at the mine mouth is not new. In recent years, however, economies of scale deriving from advances in high-voltage transmission together with the relatively higher cost of air pollution abatement and control in urban centers, have improved the relative economics of mine-mouth plants in a number of United States locations. As of the fall of 1970, electric utility plans for the construction of new fossil-fueled units of over 500 megawatts included about 18,000 megawatts of capacity at mine-mouth sites (see table 4.8). This was 43.4 percent of the coal-fired units (in the 500 MW or larger unit size category) planned for 1971 to 1975 service. In addition, electric utilities in the West planned 3,760 megawatts of capacity at two coal-fired plants—the Mohave and the Navajo—located midway between the mine and load center. When completed, the new mine-mouth and mid-point plants will consume about 60 million tons of coal annually.

The choice of mine-mouth plant sites is not determined solely by the relative economics of energy transport and air pollution control. Other important considerations include water supply for condenser cooling needs, prevailing regulations concerning thermal pollution, space for ash disposal, land costs, and local tax structure.

The number of potential sites for mine-mouth plants, where commercial coal deposits are situated near adequate water supply, is limited. In the eastern half of the United States, most of the potential sites are in the areas where the Ohio River traverses the Northern Appalachian coal basin; where the Ohio and Mississippi Rivers cross the southern portion of the Illinois basin; and where the Arkansas River cuts through the southern portion of the Western Interior basin. Because of the limited availability of cooling water in the West, there are relatively few suitable mine-mouth sites in that part of the country.

Coal Conversion

Research in the area of coal conversion to synthetic gaseous and liquid fuels has been going on for a considerable time. In the past, unfavorable economics has been a major deterrent to the development of a synthetic fuels industry. Since, however, most synthetic products can be made relatively ash and sulfur free, there has developed a greater incentive for speeding up coal conversion research and for the use of synthetic products. Potentially, therefore, synthetic fuels may become significant sources of primary energy for steam generation, particularly in areas with serious air pollution control problems.

Synthetic fuel production requires large capital expenditures and process energy. The thermal efficiency of most synthetic fuel processes is less than two-thirds. In a pure Btu market, such as exists in the electric power industry, manufacture of synthetic fuels would be justified if the cost of removing sulfur from the coal or flue gases, together with the cost of handling coal at the power plant, are greater than the cost of manufacturing and handling the "clean" synthetic product. Where transportation is involved, the cost differential of transporting fuel in one or the other form must also be considered.

Most synthetic liquid fuel processes under consideration involve production of various liquid products, including gasoline. Processes can be designed to leave variable quantities of residual char which might require special treatment for sulfur reduction prior to use as low-sulfur boiler fuel. Under some economic conditions, it may become advantageous to design a liquefaction process which would yield, in addition to gasoline, substantial amounts of residual char for electric power generation. It does not appear likely, however, that the developing coal-based synthetic liquid fuel industry will have a measurable impact on the primary fuel supply for electric power generation during the next two decades.

Synthetic gas from coal appears more likely to

TABLE 4.8

Units of 500-Megawatt Capacity and Over in Mine-Mouth Electric Plants

Units in Operation Prior to 1971

Plant	Megawatts	Operational	System
Paradise No. 3	1,130	1969	T. V. A.
Keystone No. 1	865	1967	Keystone group of PJM Pool
Keystone No. 2	865	1968	Keystone group of PJM Pool
Conemaugh No. 1	841	1970	Conemaugh group of PJM Pool
Big Sandy No. 2	800	1969	Kentucky Power Co.
Four Corners No. 4	750	1969	So. California Edison Co. and others
Four Corners No. 5	750	1970	So. California Edison Co. and others
Paradise No. 1	700	1963	T. V. A.
Paradise No. 2	700	1963	T. V. A.
Kincaid No. 1	660	1967	Commonwealth Edison Co.
Kincaid No. 2	660	1968	Commonwealth Edison Co.
Homer City No. 1	640	1969	Pa. Electric Co. & N. Y. S. Gas & Elec. Co.
Homer City No. 2	640	1969	Pa. Electric Co. & N. Y. S. Gas & Elec. Co.
Sammis No. 6	625	1969	Ohio Edison Co.
Muskingum No. 5	615	1968	Ohio Power Co.
J. M. Stuart No. 2	600	1970	Cincinnati, Columbus, Dayton Pool
Baldwin No. 1	600	1970	Illinois Power Co.
Cardinal No. 1	590	1967	Ohio Power Co.
Cardinal No. 2	590	1967	Buckeye Power, Inc.
Tanners Creek No. 4	580	1964	Indiana Michigan Elec. Co.
Mt. Storm No. 1	570	1965	VEPCO
Mt. Storm No. 2	570	1966	VEPCO
Cheswick No. 1	565	1970	Duquesne Light Co.
Ft. Martin No. 1	550	1967	Allegheny Power System & Duquesne Light Co.
Ft. Martin No. 2	550	1968	Allegheny Power System
Hatfield's Ferry No. 1	540	1969	Allegheny Power System
Hatfield's Ferry No. 2	540	1970	Allegheny Power Co.
Cayuga No. 1	500	1970	Public Service Indiana Co.
Total	18,586		

Units Scheduled for 1971 to 1975 Service

Plant	Megawatts	Operational	System
John E. Amos No. 3	1,300	1973	American Electric Power Co.
Conemaugh No. 2	900	1971	Conemaugh Group of PJM Pool
La Cygne No. 1	844	1973	Kansas City P. & L. Co.
Mitchell No. 1	800	1971	American Electric Power Co.
Mitchell No. 2	800	1971	American Electric Power Co.
John E. Amos No. 1	800	1971	American Electric Power Co.
John E. Amos No. 2	800	1972	American Electric Power Co.
Conesville No. 4	800	1973	Cincinnati, Columbus, Dayton Pool
Gorgas No. 10	700	1972	Southern Co.
Centralia No. 1	700	1971	Pacific P. & L. Co., Washington Water Power Co., Puget Sound P. & L. Co., Portland General Electric Co., Grays Harbor Public Utility District, Snohomish County Public Utility District, City of Seattle, City of Tacoma.
Centralia No. 2	700	1972	
Harrison No. 1	650	1972	Allegheny Power System
Harrison No. 2	650	1973	Allegheny Power System
Harrison No. 3	650	1975	Allegheny Power System
Sammis No. 7	650	1971	CAPCO Pool
Baldwin No. 2	604	1973	Illinois Power Co.
Baldwin No. 3	604	1975	Illinois Power Co.
Coffeen No. 2	600	1972	Central Illinois Public Service Co.
Stuart No. 1	580	1971	Cincinnati, Columbus, Dayton Pool
Stuart No. 3	580	1972	Cincinnati, Columbus, Dayton Pool
Stuart No. 4	580	1974	Cincinnati, Columbus, Dayton Pool

TABLE 4.8—Continued

Plant	Megawatts	Operational	System
Big Brown No. 1..........	575	1971	Texas Utilities Co.
Big Brown No. 2..........	575	1972	Texas Utilities Co.
Mt. Storm No. 3.........	575	1973	Virginia Electric & Power Co.
Hatfield's Ferry No. 3.....	540	1971	Allegheny Power System
Cayuga No. 2............	500	1972	Public Service Company of Indiana
Total..............	18,057		

enter the energy supply picture on a large scale sometimes during the late 1970's or early 1980's. The rate of growth of gas consumption relative to discoveries of new reserves and to estimates of total potential reserves suggest that this country will become increasingly dependent on liquefied natural gas (LNG) imports and synthetic gas from coal for its annual gas requirements. Technology for producing low-Btu synthetic gas from coal has long been available. The major emphasis in the development of coal gasification processes today is on the production of high-Btu gas with a minimum heating value of 950 Btu per cubic foot. A product of this quality could be blended with natural gas without seriously diminishing unit heating value, and could be transported economically through new or existing pipeline systems from points of manufacture to centers of consumption.

For various and frequently different reasons, the Federal Government, coal interests, elements of the natural gas industry, and electric utilities have joined to support research and development in coal gasification. The Federal Government seeks to broaden the energy resource base, the coal interests seek to develop new markets for coal, the natural gas industry seeks to provide a resources base for the long-range supply of economical gaseous fuel, and the electric utilities seek a large new source of clean fuel.

Attention is currently focusing on several coal gasification processes for the manufacture of pipeline quality gas in commercial quantities. Table 4.9 is a process summary for plants with a capacity for approximately 250 million standard cubic feet per day (scfd) or 250 billion Btu per day of product gas, except for the lignite hydrogasification plant which was designed to produce 500 billion Btu per day.

In an effort to assure a consistent approach to process evaluation, the American Gas Association (A.G.A.) developed an accounting procedure in 1961 that provides a uniform basis for estimating the cost of making pipeline quality gas. Table 4.10 summarizes certain basic economic information for the nine processes noted in table 4.9.

Basic assumptions in the computational technique include 65 percent debt and 35 percent equity financing; total investment is the sum of plant cost (fixed investment) and working capital; depreciation of fixed investment is on a 20-year straight-line basis; gross return is 7 percent of the rate base, defined at the end of the year as undepreciated fixed investment plus working capital; and interest charge on debt is 5 percent.

The estimated prices of gas at the plant, given in table 4.10 reflect substantial reductions from earlier estimates. The prices, although still substantially above the national average prices paid by electric utilities for natural gas (25.4 cents per million Btu in 1969), are rapidly approaching wholesale (city-gate) prices for natural gas, particularly in the Middle Atlantic States.

Further process improvement on the one hand, and upward pressures on city-gate natural gas prices on the other hand, are apt to bring synthetic gas into competitive range and lead to the development of a large synthetic gas industry which will have a significant impact on the gaseous fuel supply picture for electric power generation.

Natural Gas

In 1970, 3.9 trillion cubic feet of natural gas were burned to generate electricity in utility power plants. This was nearly 18 percent of all natural gas consumed in the country and about 26 percent of all gas used for industrial pur-

TABLE 4.9

Process Summary for Synthetic Pipeline-Gas Plants [1]

	Steam-oxygen	Molten salt	Hydrogasification: Raw coal	H_2 by steam-oxygen	H_2 by steam-iron	Synthesis gas electrothermal	Lignite synthesis gas electrothermal	CO_2 acceptor (lignite)	Fluid Bed
Design capacity, 10^6 scfd	250	250	250	265	266	275	523	250	250
Heating value, BTU/scf	925	920	982	947	941	937	954	948	943
Coal or lignite, tons/day [2]		13,250	14,240	14,339	17,791	17,791	55,640	26,760	15,100
Coal heating value BTU/lb.	13,490	13,650	12,700	12,410	12,390	12,390	7,345	6,613	12,700
Purchased power, kW						355,600		5,120	
Oxygen, tons/day	5,020		4,500	3,810					5,150
By-products									
Char, tons/day						4,160			
Low BTU gas, 10^9 BTU/day					81				
Oil, b/d							10,000		2,800
Benzene, b/d							2,230		
Sulfur, tons/day	242	[3] (130)	159		[3] (390)	390			62
Power, kW		158,000					126,600		

[1] Revised from The Oil and Gas Journal, February 24, 1969. Synthetic Pipeline Gas Prices Calculated to Settle Within Range of 36.3–58.2¢/Mcf, by C. L. Tsaros and T. J. Joyce, IGT.

[2] Coal feed unless stated otherwise.

[3] Potential, not included in cost figures.

Note: scfd—standard cubic feet per day; scf—standard cubic feet; b/d—barrels per day.

TABLE 4.10

Economics of Synthetic Pipeline-Gas Processes, Summary [1]

Process	Total investment dollars [2]	Capacity 10^9 BTU/day	20-year average price of gas at stated coal cost. ¢/10^6 BTU ($/ton): Coal	Gas
Steam-oxygen	142,348,000	231	14.8 (4.00)	56.4
			16.1 (4.35)	58.2
Molten salt with by-product power	135,295,000	230	14.65 (4.00)	54.2
			16.1 (4.39)	56.6
Hydrogasification				
Raw coal	[3] 140,000,000	229	15.8 (3.50)	53.0
H_2 by steam-oxygen	147,221,900	251	16.1 (4.00)	57.8
H_2 by steam-iron	105,289,000	250	16.1 (4.00)	50.2
Syn. gas electrothermal	93,208,000	258	16.1 (4.00)	51.1
Lignite, syn. gas electrothermal	236,171,000	500	10.0 (1.47)	36.3
CO_2 acceptor	82,444,000	237	10.0 (1.33)	39.3
			11.3 (1.50)	41.3
Fluid bed	[3] 165,000,000	236	13.8 (3.50)	54.0

[1] Revised from The Oil and Gas Journal, February 24, 1969. Synthetic Pipeline Gas Prices Calculated to Settle Within Range of 36.3–58.2¢/Mcf, by C. L. Tsaros and T. J. Joyce, IGT.

[2] Installed equipment or bare cost is 83 to 90% of total investment. Fixed investment (total loss working capital) is 94 to 96% of total investment.

[3] Includes coal mine.

poses. The use of natural gas for electric power generation has grown rapidly. In the 1930's power plant consumption of natural gas amounted to only about 7 percent of total consumption. Electric utility consumption of gas during the 10-year period 1961–1970 is shown in table 4.11.

While the forecasts of future fuel consumption prepared for and summarized by the various Regional Advisory Committees indicate that the electric utilities will continue to demand increasing quantities of natural gas to fuel power plants, the rate of growth in consumption of gas by electric utilities is expected to decline rapidly. The average growth rate to 1990 is estimated at 0.4 percent annually, compared with about 9 percent over the past several decades and 8 percent in the most recent decade. Projections of the consumption of gas for electric power generation to 1990 are shown in table 4.1.

The projected slowing of the rate of growth of gas used for electric generation is based on a number of factors, two of which are particularly significant. First, nuclear, coal and oil-fired stations, despite continued higher initial capital investment, are expected to become increasingly competitive with gas-fired plants even in areas where gas has for some time been the prime fuel for electric generation.

Second, electric utilities are finding it increasingly difficult to obtain long-term firm commitments for gas supplies at the time decisions on design are made. A contributing factor to this difficulty is the size of the fuel source required for the large units now being planned. For example, a 1,000 megawatt unit intended to operate at an average of 5,000 hours (57 percent plant factor) per year for 20 years would require a total of approximately 1 trillion cubic feet of gas.

National Gas Survey

The Federal Power Commission, in February 1971, initiated the National Gas Survey. In the Order prescribing procedures for the conduct of the Survey, the Commission pointed out:

> "To accomplish the objectives of the Natural Gas Act, in providing for the ultimate consumer an adequate and reliable supply of natural gas at a reasonable price and the Nation a vital energy resource base, the Commission will direct the conduct of the Survey through the members of the Commission and its staff."

The Survey, comparable to the National Power Survey, is intended to enhance the Commission's ability to regulate effectively through policies to provide a continuing reliable supply of gas to meet consumers needs.

Among the matters to be examined by the Survey are the gas supply/demand balance problem, the role of natural gas in air pollution control, the supply-price-demand relationship, interfuel competition and the role of synthetic fuels as a source of gas.

TABLE 4.11

Total Domestic and Utility Consumption of Natural Gas, 1961–1970

Year	Total Domestic Consumption in 10^9 Cubic Feet	Electric Utility Consumption in 10^9 Cubic Feet	Utility Consumption as a Percent of Total Consumption	Average Cost to Utilities "as Burned" in Cents Per 10^6 Btu
1961	13,010.7	1,825.1	14.0	25.1
1962	13,814.7	1,966.0	14.2	26.4
1963	14,561.0	2,144.5	14.7	25.6
1964	15,452.0	2,322.9	15.0	25.4
1965	16,033.2	2,321.1	14.5	25.1
1966	17,191.7	2,609.9	15.2	25.1
1967	18,172.9	2,746.4	15.1	24.7
1968	19,459.9	3,147.9	16.2	25.1
1969	20,922.8	3,486.4	16.7	25.4
1970	22,412.0	3,894.0	17.4	N.A.
70/61 Ratio	1.72	2.13		

A matter of highest priority is the determination by the Federal Power Commission of the natural gas reserves of the United States. In carrying out this independent survey and analysis, the Commission staff and other professionals commissioned by the FPC, and under direction of the Commission, will use geophysical and geological data to make individual estimates of natural gas reserves on a reservoir by reservoir basis of a broad sampling of natural gas fields. This statistically valid sample will be extrapolated to cover the total census of natural gas fields so that a comprehensive estimate of natural gas reserves in the United States may be established.

Natural Gas Resources

The American Gas Association (A.G.A.), in conjunction with the American Petroleum Institute (API) and the Canadian Petroleum Association, prepares an estimate of the proved recoverable reserves of the natural gas in the United States as of December 31 of each year. As of December 31, 1970, these were 259.6 trillion cubic feet (excluding 31.1 trillion cubic feet in Alaska) of which 90 percent were in the 5 adjoining States of Texas, Louisiana, Oklahoma, Kansas, and New Mexico. The reserves, shown in table 4.12 are gas for which both specific location and quantity are known with a high degree of certainty. That is, existence in a specific location has been established by drilling into the reservoir containing the gas and the quantity has been estimated with reasonable precision. The general distribution of the major United States gas reserves is shown in figure 4.5.

These reserves amount to 11.9 times current annual production. If this were all of the gas available, a shortage would develop rapidly. A shortage would be felt first by electric utilities because of the large volume they consume, the relatively low price they pay for gas, and the inability of some plants to switch to other fuels. Additional quantities of gas continue to be found, but the average discovery of 16.6 trillion cubic feet per year for the last 10 years is less than current annual consumption. In the past three years, additions to reserves were only 12.0 trillion cubic feet in 1968, 8.3 trillion cubic feet in 1969, and 11.1 trillion cubic feet in 1970. During those three years the Nation's finding-to-production ratio (excluding Alaska) fell to 0.6, 0.4, and 0.5, respectively.

TABLE 4.12

Estimated Total Proved Recoverable Reserves of Natural Gas in the United States [1]

[Trillions of Cubic Feet—14.73 psia, at 60° F]

Reserves as of December 31, 1969		269.9
Additions to Reserves During 1970:		
Net extensions and revisions	6.0	
New field discoveries	1.8	
New reservoir discoveries	3.3	
Net changes in underground storage	0.4	
Total Additions		11.5
Net Production		−21.8
		259.6
Reserves as of December 31, 1970		
Non-associated	199.4	
Associated-dissolved	56.2	
Underground storage	4.0	

[1] Excluding Alaska.

Table adapted from "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1970," Volume 25, May 1971: American Gas Association, Inc.; American Petroleum Institute; Canadian Petroleum Association.

While the exact amount of gas yet to be found is, of course, unknown, the problem is receiving study and estimates are being prepared. The Potential Gas Committee [3] estimated that as of December 31, 1970, the potential supply, including Alaskan potential, beyond the proved reserves of 290.7 trillion cubic feet was 1,178 trillion cubic feet. This was divided into 257 trillion cubic feet of probable reserves, 387 trillion cubic feet of possible reserves and 534 trillion cubic feet of speculative reserves.

The United States Department of the Interior estimates that originally there were about 5,000 trillion cubic feet of natural gas in place in the

[3] The Potential Gas Committee is sponsored by the Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines and is composed of members from the gas producing, pipeline, and distribution industry, observers from State and Federal regulatory bodies, American Gas Association, American Petroleum Institute, Independent Natural Gas Association of America and National Association of Regulatory Utility Commissioners.

United States. Of this quantity only half, 2,500 trillion cubic feet, will be found and commercially recoverable. From this, about 1,000 trillion cubic feet of gas already found and either produced or included in the proved reserve above should be subtracted, leaving over 1,500 trillion cubic feet yet to be found.

Other estimators have used other methods with widely varying results. The ultimate quantity of gas produced will be determined in large part by future technology. The Plowshare Program discussed below is a prime example of possible future technology which could have a profound effect on future natural gas reserves by raising the recovery factor in some types of reservoirs which now cannot be produced economically.

Plowshare Program

Project Gasbuggy is the first experiment to be conducted under the Atomic Energy Commission's "Plowshare" program for the commercial application of nuclear explosives. The general aim of the experiment is to prove the feasibility of nuclear stimulation of low-productivity gas reservoirs. The principal objectives are to determine the effects of the nuclear explosion on the gas-bearing formation: how much fracturing occurs, the seismic effects that will be transmitted through the soil to surrounding structures, the characteristics of the radioactive materials formed, and ways of disposing of the materials. The project is being conducted under the joint auspices of the Atomic Energy Commission, United States Bureau of Mines, and the El Paso Natural Gas Company.

On December 10, 1967, a 26-kiloton nuclear charge was detonated at a depth of 4,240 feet in the Pictured Cliffs formation of the San Juan Basin in northern New Mexico. The purpose of the explosion was to pulverize, melt, and vaporize the sandstone rock, thus creating a rockfilled chimney containing an estimated 1.6 billion cubic feet of gas. The Pictured Cliffs formation, when subjected to conventional fracturing, has an ultimate recovery factor of about 10 percent of the original gas in place. It has been estimated by the sponsors that nuclear fracturing could raise the gas recovery to as much as 50 to 80 percent.

A year after detonation it was determined that most of the principal objectives of the experiment had been met, and that more similar gas stimulation research projects would be required.

It was decided that additional tests are needed in the Gasbuggy area as well as other areas with different geological conditions before definitive conclusions can be drawn. At the present time, four other projects are in the planning stage. One of these, Project Rulison, was initiated during the summer of 1969. Three other projects that are pending are Rio Blanco in northern Colorado and Wagon Wheel and Wasp in western Wyoming.

Nuclear gas stimulation could find widespread application to low permeability gas-bearing reservoirs throughout the Rocky Mountain area if proven commercially feasible by Gasbuggy or other experimental projects. Based on present knowledge, however, it is impossible to predict the magnitude of gas reserves that may be released by this technique. In any event, nuclear stimulation techniques are not expected to have a significant effect on domestic supply in the near future.

Natural Gas Imports

Additional natural gas resources are available to the United States consumer from outside the bounds of the 48 contiguous States. Natural gas has been imported from the fields of neighboring Canada and Mexico for many years. While these imports amounted to only 3.5 percent of United States consumption in 1970, they were vitally important for some areas. Gas may also be transported across Canada from Alaska.

Early exploration of the recently discovered oil and gas deposits of Alaska indicate that potential reserves are large, amounting to an estimated 327 trillion cubic feet. Pipeline transport of gas across Alaska and Canada, however, would be complex and costly. Preliminary estimates by gas transmission companies show that if the technical and ecological problems associated with laying and maintaining gas pipelines in permafrost areas can be resolved, Alaskan gas may be delivered in the Northern Plains in the last half of this decade at approximately 75 cents per Mcf (at 1970 prices).

The increased transport capabilities provided by the liquefaction of natural gas, described in a later section of this chapter, have encouraged programs now being implemented to bring

quantities of liquid natural gas from sources beyond the seas. Worldwide resources are potentially available to augment our domestic and continental resources although other countries also will share the world supplies.

Residual Fuel Oil

Petroleum is consumed in the form of a variety of liquid and solid products obtained from it. Residual fuel oil, as the name implies, is a residual refinery product and normally competes directly with natural gas and coal for heavy-fuel uses, such as the generation of steam at electric power plants. Because residual fuel oil is quite viscous and cannot be economically moved by pipeline over long distances, its competitive position is greatest in areas with cheap water transport facilities or in areas adjacent to petroleum refineries. Some low-sulfur residual oil is less viscous and can be moved economically by pipeline over greater distances.

Nationally, residual fuel oil-fired plants contribute about 15 percent to generation by fossil-fueled plants. During the 1961–1965 period, fuel oil consumption by electric utilities increased gradually. Beginning in 1965, however, electric utility demand for fuel oil increased rapidly, as shown in table 4.13.

Although residual fuel oil accounts for a relatively small portion of total electric generation, its role in some parts of the country is very significant. For example, in 1970 residual fuel oil accounted for approximately 82 percent of total thermal generation in the New England area, 38 percent in the Middle Atlantic area (New Jersey, New York, and Pennsylvania), 44 percent in Florida, 17 percent in California, and 100 percent in Hawaii.

The growth in residual fuel oil consumption at power plants during the second half of the past decade proceeded at a greater rate than the growth in electric power generation. This has been due to new construction of oil-burning facilities and to the shift to the use of fuel oil by some dual-fuel plants, mostly in the Northeast. A major attraction of residual oil during the 1960's was its declining price, as shown in table 4.13. More recently, the demand for residual oil has increased because of expanding use of low-sulfur residual oil to meet sulfur oxide emission regulations.

Residual Fuel Oil Supply

Modern refining technology has made it possible to substantially reduce the proportion of residuum produced from each barrel of crude oil. The actual quantities of residual oil produced vary depending on the price and quality of the crude, processing costs, demand for the higher-priced distillate products, transport costs, and the demand and price of residual oil. Because of the relatively high price of domestic crude oil,

TABLE 4.13

Total Domestic and Utility Consumption of Fuel Oil, 1961–1970

Year	Total Domestic Consumption in 10^6 Barrels	Electric Utility Consumption in 10^6 Barrels [1]	Utility Consumption as Percent of Total Consumption	Average Cost to Utilities "as Burned" in Cents Per 10^6 Btu
1961	548.7	85.7	15.6	35.5
1962	545.8	85.8	15.7	34.5
1963	538.9	93.3	17.3	33.5
1964	554.6	101.2	18.2	32.6
1965	587.0	115.2	19.6	33.1
1966	626.4	140.9	22.5	32.4
1967	651.9	161.3	24.7	32.2
1968	668.2	188.6	28.2	32.8
1969	721.9	250.9	34.7	31.9
1970	804.2	332.3	41.3	N.A.
70/61 Ratio	1.47	3.88		

[1] Figures include small quantities of distillate oils.

the large demand for distilled products, and the low price for residual oil in relation to other petroleum products, United States refiners find it profitable to crack the oil as much as possible. Thus, the yield of residual oil from each barrel of crude has been steadily decreasing. During the ten-year period 1961–1970, while refinery runs increased by over 30 percent, domestic residual oil output dropped from 315.6 million barrels in 1961 to 275.5 million barrels in 1970. The demand for residual oil does not normally effect increases in crude production and refinery runs, or greater refinery yields of residual oil at the expense of distillate products. In the last quarter of 1970, however, prices for residual oil increased sufficiently to elicit greater yields of residual oil.

Total original crude oil resources in the United States and in its continental shelves to a water depth of 200 meters are estimated at 2,380 billion barrels as compared with 90 billion barrels which were withdrawn to January 1, 1969. The remaining petroleum resources of the United States are adequate to support consumption for many years into the future. The discovery rate, however, is such that only a 9-year supply of crude oil at the recent rates of production has been classed as proved reserves. The real issue, therefore, is whether the vast United States crude oil resources can be located at a satisfactory rate and whether they can be produced at costs competitive with other energy sources.

Large oil reserves were recently discovered along the northern shores of Alaska. Two distinct methods for bringing Alaskan crude oil to consumers in the lower 48 States are being considered. One would involve a north-to-south trans-Alaskan pipeline and shipment by ocean-going tankers to the West Coast. The other would involve the use of extra large oil tankers in a northern route around the North American Continent. In addition, an oil pipeline across the Canadian Arctic has been discussed. In any case, transportation costs will be high, adding substantially to the relatively high cost of production in polar regions.

Although development of the North Slope Alaskan oil fields has already begun, it does not appear likely that oil deliveries from that area will have a significant effect on the domestic liquid fuel supply until perhaps the latter part of this decade.

It is expected that the Nation will become increasingly dependent on foreign sources of supply for its residual oil requirements. Approximately 90 percent of our residual oil imports originate in the Western Hemisphere. Venezuela and the Netherlands Antilles are the principal suppliers, accounting for nearly three-quarters of all imports. The domestic residual oil supply picture for 1961–1970 is shown in table 4.14. In time, however, as the World demand for distillate products continues to increase, it is reasonable to expect that residual oil yields in foreign

TABLE 4.14

Domestic Supply of Residual Fuel Oil,[1] 1961–1970

Year	Crude Runs to U.S. Refineries, in 10^6 Barrels	Residual Oil Yield, %	Residual Oil Output, in 10^6 Barrels	Residual Oil Imports, in 10^6 Barrels	Residual Oil Exports, Transfers from Crude and Stock Changes, in 10^6 Barrels	Total Domestic Consumption, in 10^6 Barrels
1961......	2,987.2	10.6	315.6	243.3	−10.2	548.7
1962......	3,069.6	9.6	295.7	264.3	−14.2	545.8
1963......	3,170.7	8.7	275.9	272.8	−9.8	538.9
1964......	3,223.3	8.3	266.8	295.8	−8.0	554.6
1965......	3,300.8	8.1	268.6	345.2	−26.8	587.0
1966......	3,447.2	7.7	264.0	376.8	−14.4	626.4
1967......	3,582.6	7.7	276.0	395.0	−20.0	651.9
1968......	3,774.4	7.3	275.8	409.9	−17.5	668.2
1969......	3,879.6	6.9	265.9	461.6	−5.6	721.9
1970......	4,005.6	6.4	257.5	557.8	−11.1	804.2

[1] Source: U. S. Bureau of Mines Minerals Yearbooks

refineries will follow the United States trend and the supply of residual oil may become tighter.

Oil Import Control Program

The Mandatory Oil Import Control Program was established on March 10, 1959, after a finding by the Director of the Office of Civil and Defense Mobilization that the level of imports at that time (about 18 percent of total supply) threatened to impair the national security. Thus, primarily for reasons of national security, imports of crude oil and products other than residual fuel oil east of the Rocky Mountains were held to not more than 12.2 percent of the amount of domestic crude oil and natural gas liquids which the Secretary of the Interior estimated would be produced during the period for which the import allocations were granted. Imports of crude oil on the West Coast and residual fuel oil on the East Coast were permitted to the extent necessary to make up the differences between demand and domestic supply of these commodities.[4]

In 1966, there was a complete relaxation of restrictions on the import of residual fuel oil on the eastern seaboard. This made foreign residual fuel oil more accessible and accelerated the downward trend of residual fuel oil prices in the United States, substantially increasing the demand for it. As evident from tables 4.13 and 4.14, residual fuel oil users in the United States, including electric utilities, are becoming increasingly dependent on foreign sources of supply.

In March of 1969, the President established a Cabinet Task Force on Oil Import Control to make a comprehensive review of the United States oil import program. The Task Force examined the effects of the present program and the impact to be expected from possible changes in the program. In February of 1970, a majority of the Task Force recommended that the present system of import controls be replaced with a system of tariffs geared to a somewhat lower domestic price of oil. A simultaneous report by a minority of the Task Force recommended continuation of import controls, essentially in their present form.

All Task Force members agreed on the need for a new management system to set policy for the oil import program. Consequently, the President gave the Director of the Office of Emergency Preparedness the responsibilities for policy direction, coordination, and surveillance of the oil import program, acting with the advice of a permanent cabinet level Oil Policy Committee. Most day-to-day administrative functions will continue to be performed by the Oil Import Administration.

The Oil Policy Committee found that recent interruptions in the flow of oil to Europe, while comparatively small in quantity, had caused significant disruption of the international oil situation. Furthermore, the Committee believed that the country would be in a transitional situation with regard to oil, in part because of the uncertainty of when Alaskan oil will become available and because of the effects of environmental programs. Finally, the Committee concluded that the problem of preventing dependence on relatively insecure sources of supply even as early as 1975 was more severe than originally estimated. Consequently, the Oil Policy Committee recommended to the President that consideration of the tariff system of import control be abandoned and that the quota system be continued with some improvements.

Low-Sulfur Residual Fuel Oil for the Electric Power Industry

In 1968 and 1969, the greatest new demand for low-sulfur residual oil (less than 1 percent sulfur by weight) was by electric utilities in the Middle Atlantic area. In the Los Angeles Basin, regulations prohibiting the use of fuel oil (or coal) containing more than 0.5 percent sulfur have been in effect for several years. In the past, practically all of the low-sulfur residual fuel oil for the electric utility market was obtained through blending high-sulfur residual fuel oil with (1) naturally low-sulfur residual oil produced from Indonesian crudes and from Libyan and Nigerian crudes; (2) light distillates; and (3) desulfurized residual oil.

During 1969, several companies had under construction new facilities for the desulfurization of residual fuel oil in the Caribbean area. In addition, several plants for the production of low-sulfur residual oil, primarily from the bottom fraction from the atmospheric distillation of high-sulfur Venezuelan crudes, were proposed for the East Coast. Some of these plants would

[4] United States Department of the Interior, United States Petroleum Through 1980, Office of Oil and Gas, July 1, 1968.

produce residual fuel oil with a sulfur content as low as 0.3 percent. Facilities for the production of low-sulfur residual oil may in time supply much of the low-sulfur residual fuel oil needs of the electric power industry, as long as imports of residual oil remain unrestricted.

Increasing quantities of naturally low-sulfur residual oil are becoming available from Africa, where production of extremely low-sulfur crude oil is mounting rapidly, though recently the Libyan government has been limiting production. The low-sulfur crude oil of Libya, and the residual oil produced from it, is mostly paraffin based containing relatively high proportions of wax, somewhat complicating its use. On the other hand, Nigerian oil is essentially wax free.

Oil Shale

In analyzing the future United States petroleum demand-supply picture, the Department of the Interior forecasts[5] that beginning in 1980 the Nation's total demand for petroleum will outpace total supply, even in the face of ever-increasing imports from abroad. To avoid future shortages it may become necessary to develop supplemental indigenous sources of oil supply such as oil shale, tar sands, and synthetic liquid fuels from coal.

Large areas of the United States contain oil shale deposits. Areas in the States of Colorado, Utah, and Wyoming underlain by sedimentary rocks of the Green River formation are of greatest potential for commercial shale oil production. About one-half of the area has been explored and the reserves have been estimated to include about 590 billion barrels in higher-grade shale formations which are at least 10 feet thick and yield over 25 gallons of shale oil per ton. An additional 1,150 billion barrels are estimated to be included in lower-grade deposits yielding 15 to 25 gallons of oil per ton. The unappraised oil shale resources may contain similar quantities of oil-bearing organic material.

Development of the vast oil shale resources has been delayed primarily by the lack of satisfactory technology—mining and retorting of oil shale—which would enable production of shale oil at competitive prices. Development of an oil shale industry has been further complicated by the shortage of water in the area, inadequately defined leasing policiés, and the possible adverse environmental impact.

Recognizing the long lead times associated with the establishment of a large-scale oil shale industry, the Department of the Interior has recently announced a Prototype Oil Shale Leasing Program for oil shale development to help meet the increasing energy requirements of the Nation. According to the Interior program, if oil shale leases are issued in 1972, shale oil production should begin about 1975 at an initial rate of approximately 18 million barrels per year. Presumably, the first-generation technology needed for this rate of production will continue to be improved from 1976 to 1980. Production capacity might increase by 18 million barrels per year, reaching a total production capacity of about 100 million barrels per year in 1980. After 1980, the second generation extraction-retorting systems are expected to permit annual additions to shale-oil productive capacity of 37 to 73 million barrels per year, reaching a cumulative capacity in 1985 of 300 to 500 million barrels per year.

It is most difficult to forecast what effect residual fuels from the oil shale industry will have on the fuel supply for electric power generation in the next 20 years. It is entirely possible, however, that the oil shale industry will have an indirect effect in that oil from shale may, in time, set upper limits on crude oil prices.

Fuel Transport

Except where nuclear fuel is employed to generate electricity in power plants located near load centers, the transport of energy in one or another form constitutes a significant part of the total cost of electricity. Either the fossil fuels—coal, gas, and oil—must be transported from the source to the generating plant; or where the electric energy is generated at the source of fuel, as in the case of mine-mouth plants (coal), well-head plants (gas), or plants located near refineries (residual fuel oil), the generated electricity must be transported to load centers by wire. The choice of energy transport is usually one of economics with the environmental impact now receiving increasing emphasis.

[5] U. S. Department of the Interior, A Planning Program for Oil Shale Development, May 1970.

Coal Transport

Practically all types of surface transport are employed in the delivery of coal to electric utilities. Table 4.15 shows bituminous coal and lignite shipments to electric utilities, by mode of transport during 1959 and 1968. A large 275-mile pipeline for the delivery of coal in slurry form from eastern Arizona to southern Nevada was completed in 1970.

Rail Transport

Coal is the largest single item of all-railroad freight traffic. Important factors in the rapid growth of railroad coal shipments to electric utilities have been the development of the unit-train concept and passage of the Transportation Act in 1958. Prior to 1958, the prevailing volume rate rule would not permit multi-car rates to be less than 85 percent of single car rates. Passage of the Act and subsequent interpretations by Federal courts made it possible for railroads to offer incentive rates to electric utilities and other volume consumers of coal.

The introduction of unit trains has enabled railroads to reduce freight rates substantially, with significant savings to electric utilities. In the unit-train or shuttle-train concept, both locomotive power and commodity-carrying cars operate as a single unit between the mine and consignee. Trains are broken up only for necessary repair and servicing of particular cars or engines, which are immediately replaced by reserve equipment. Simplified car accounting, elimination of intransit switching and reduction of terminal switching, and faster turnarounds have increased substantially the utilization of railroad cars. Unloading of 7,000 to 10,000-ton train loads in four to eight hours is now quite common. Some utilities are capable of even better performance. For example, at the Bull Run steam-electric plant of the Tennessee Valley Authority, a train of 72 100-ton cars can be unloaded in 20 minutes, with a total turnaround time of less than one hour.

The cost per ton of unit-train coal transport is primarily a function of distance, annual volumes, and the number of railroads involved. Frequently, electric utilities find it advantageous to own coal cars to assure their availability and to provide optimum maintenance. Figure 4.6 shows 1968–1969 average unit-train rates in mills per ton-mile for representative hauling conditions. Due to inflationary pressures all freight rates have increased since that time.

Water Transport

Coal movements on inland waterways are essentially limited to the central eastern portions of the country: on the Kanawha and Monongahela Rivers to the Pittsburgh area; on the Illinois and Upper Mississippi Rivers to Chicago and the Twin Cities; from the Western Kentucky and Southern Illinois fields to steam plants located on the Lower Ohio, Tennessee and Mississippi Rivers; and from Western Kentucky fields to the Gulf via the Ohio and Missis-

TABLE 4.15

Bituminous Coal and Lignite Shipments to Electric Utilities, by Mode of Transport, 1959 and 1968[1]

	1959		1968	
	Million Tons	Percent of Total	Million Tons	Percent of Total
All-rail	75.6	45.2	153.2	51.5
Water	58.2	40.8	100.9	34.0
River and Ex-river[2]	(38.6)	(23.1)	(67.1)	(22.6)
Great Lakes	(15.5)	(9.3)	(20.8)	(7.0)
Tidewater	(14.1)	(8.4)	(13.0)	(4.4)
Truck	13.3	7.9	25.7	8.6
Tramway, Conveyor, and Private Railroad	10.2	6.1	17.5	5.9
Total	167.3	100.0	297.3	100.0

[1] U.S. Bureau of Mines Mineral Market Reports. Bituminous Coal and Lignite Distribution.

[2] In Ex-river shipments final delivery to consumers is by an overland transport method.

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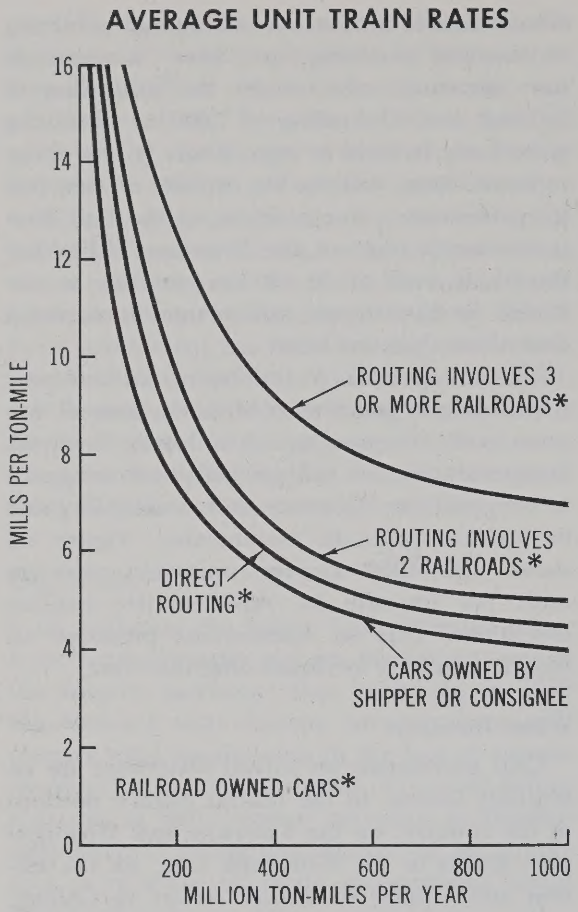


Figure 4.6

sippi Rivers. In addition, some coal moves on the Great Lakes.

Conventional volume movements of coal in barges normally involve three sets of barges and one tow boat—an arrangement necessitated by the slowness of loading and unloading barges. One set of barges remains at the mine for loading while the second set is at the utility plant being unloaded and the third set is in transit. Only a small proportion of the operating coal mines, however, are located sufficiently close to navigable rivers to permit direct loading of coal into barges. In other instances, the coal cannot be delivered to the consumer directly from the barges. Consequently, nearly two-thirds of the coal shipped on the waterways requires transshipment.

In spite of the apparent drawbacks, barge transport of coal is relatively inexpensive and remains in demand where transshipments are not required, or where a significant portion of the distance from the mine to consignee can utilize barge transport. In some instances, availability of return freight helps to keep barge rates low.

To maintain their competitive position, barge companies are installing rapid loading and unloading equipment, and barges are being designed to accommodate this equipment. Introduction of modern equipment, capable of loading barges at the rate of 4,000 to 5,000 tons of coal per hour, has in turn led to the recent introduction of the "unit-barge" movement of coal, patterned largely after the unit-train concept.

Pipeline-Slurry Transport

The pioneering effort in long distance, coal slurry transport by pipeline was the Consolidation Coal Company's 108-mile system from Cadiz, Ohio to the Eastlake plant of the Cleveland Electric Illuminating Company. Built in 1957, the 10-inch diameter pipeline transported an average of over 1,000,000 tons of coal per year. It was shut down in 1963, when railroad freight rates were drastically reduced on all coal leaving District 8 in Ohio. The economic impact which this system made on rail tariff rates and the role it played in the development of the unit-train concept are beyond question.[6]

Generally, because of the high capital investments and the inherent characteristics for achieving substantial economies of scale, pipeline-slurry systems are competitive only when large annual volumes of coal are involved and if the contractual periods of coal delivery are relatively long. Other important considerations in comparing the economics of pipeline systems and unit-train transport are the length of the rail siding required and the amount of work necessary to upgrade the existing track in order to deliver coal by rail.

With these considerations in mind, the Peabody Coal Company contracted to deliver by pipeline at least 117 million tons of coal over a period of 35 years, from Black Mesa, Arizona, to the 1,500 megawatt Mohave Plant in southern

[6] The technology of pipeline-slurry transport of coal and a description of the Cadiz-to-Cleveland pipeline are presented in the 1964 National Power Survey, Volume II, Advisory Committee Report No. 21, Fuels for Electric Generation.

Nevada. Conventional transport by rail would have required the construction of 135 miles of spur track from Black Mesa and from the plant site to the Santa Fe Railway's main line. The 18-inch, 275-mile pipeline system, including the slurry preparation plant, a pump station at the point of origin, and three intermediate booster pump stations, was completed in 1970 at a cost of about $35 million. Figure 4.7 shows the location of the pipeline system.

Run-of-the mine coal, averaging approximately 11,000 Btu per pound, about 0.5 percent sulfur, and 7.9 percent ash, is delivered to the slurry preparation plant in particle sizes of up to two inches. A series of crushing and grinding mills reduces the particle size. The dry coal will be mixed with water in a 50–50 weight ratio prior to delivery to the pipeline.

The Mohave Plant requires 660 tons of coal per hour. The slurry, therefore, will move through the pipeline system at a rate of 4500 gallons per minute and at a velocity of 5.8 feet per second. The coal slurry is pushed through the pipeline by thirteen, 1700-horsepower pumps installed at the four pumping stations along the line. Delivered coal slurry is stored temporarily in tanks to provide uniform, uninterrupted flow to the plant. The coal slurry is dewatered in centrifuges and fed to pulverizers, where the surface moisture content is reduced to about 25 percent prior to delivery to the boilers. Water from the centrifuges is run through a clarifier

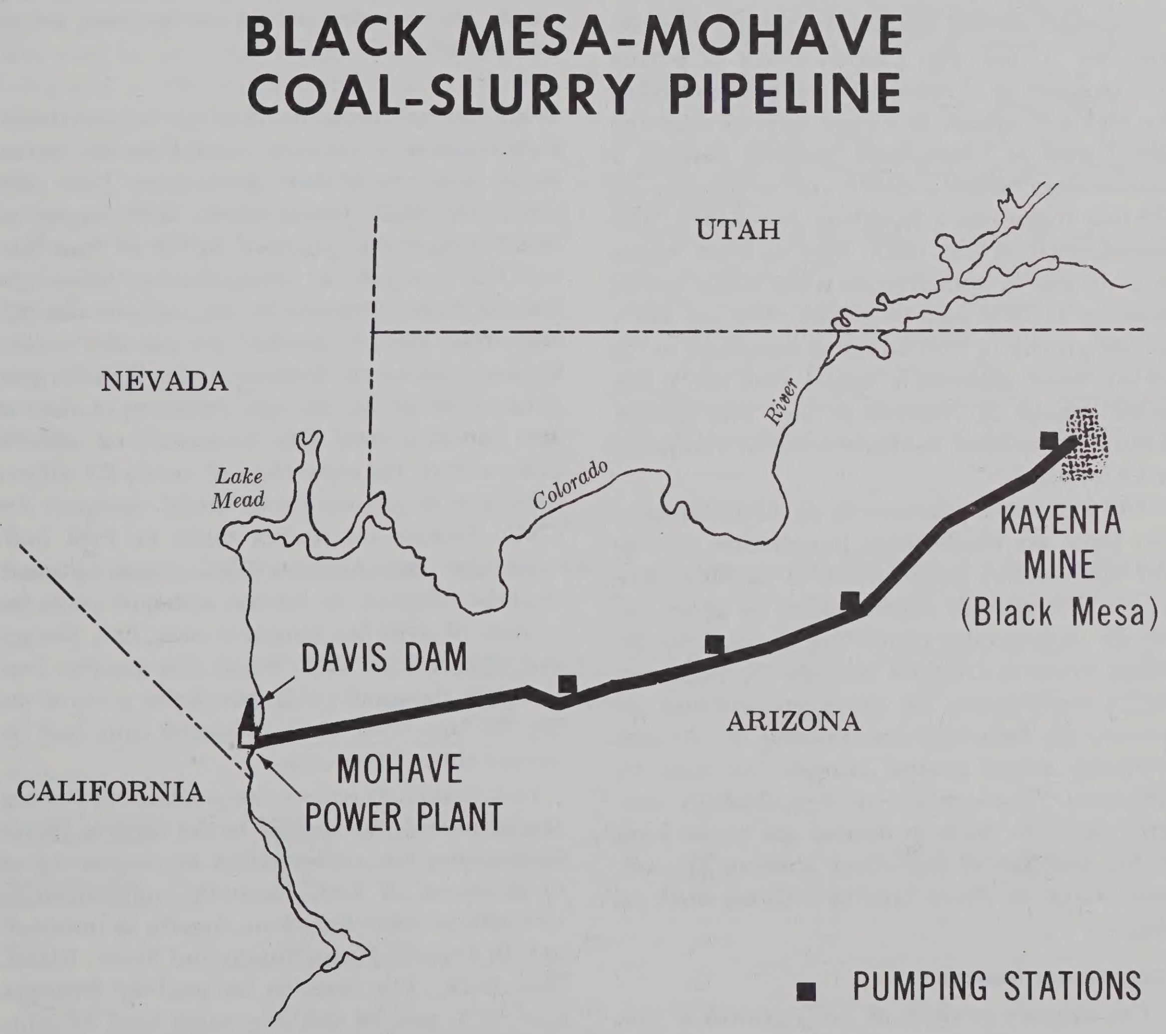


Figure 4.7

and then used as makeup for the plant circulating water system.

Transportation of Natural Gas

The movement of natural gas from the reservoir to the ultimate user requires a continuous pipe between these points. More than 891,000 miles of pipeline have been installed by gas companies to accomplish this movement. More than 248,000 miles of these pipes are classified as transmission mains of which about 72 percent are subject to the jurisdiction of the Federal Power Commission. Most of these lines originate in the major producing states of Texas, Louisiana, New Mexico, Oklahoma and Kansas. Natural gas is now marketed in all of the forty-eight contiguous states and Alaska.

Liquefied Natural Gas (LNG)

Liquefied natural gas consists mainly of methane; but it may also contain traces of ethane and propane. It is essentially colorless and odorless and will seldom be viewed directly since the liquid state at atmospheric pressure requires a temperature below −258°F. At a pressure of 673 psia it remains a liquid up to −116°F. The regasification of one cubic foot of LNG results in a volume of approximately 632 cubic feet of methane at 70°F and 14.73 psia. The gas has a specific gravity of 0.55 to 0.6 as compared to 1.0 for air. Since methane is lighter than air, it disperses rapidly if released to air. The specific gravity of liquefied methane is 0.3 as compared to 1.0 for water.

The four basic processes in an LNG liquefaction plant are purification, liquefaction, storage and vaporization. Liquefaction of purified natural gas is commonly accomplished by either the cascade or expander cycles. Storage of LNG involves cryogenic facilities that are (1) inground, (2) a combination of above ground and inground, (3) below ground concrete, or (4) conventional above ground metallic or concrete containers. Vaporization or regasification converts the LNG back to normal gas vapor form by the addition of heat from ambient air, ambient water, or direct fired or indirect fired vaporizers.

International Transport

The primary promise of LNG growth is that it opens sources of supply of natural gas which could not otherwise be reached. Several large-scale supplies of overseas natural gas for importation into the United States have been proposed for LNG development. The largest to date has been that proposed by the El Paso Natural Gas Company in its application before the Federal Power Commission to purchase one billion cubic feet of liquefied gas per day over a 25-year period from Sonatrach, the Algerian government-owned oil and gas company. A fleet of nine tankers, each with a capacity of 120,000 cubic meters, the equivalent of nearly 2.5 billion cubic feet in gaseous form, would transport the LNG. Reports on studies made in 1969 indicated that this Algerian LNG could be made available shipside in eastern seaboard ports for around 50 cents per thousand cubic feet. Storage and regasification costs would add another four cents per thousand cubic feet to the price of the gas. By late 1970, these estimated costs had increased about 20 percent.

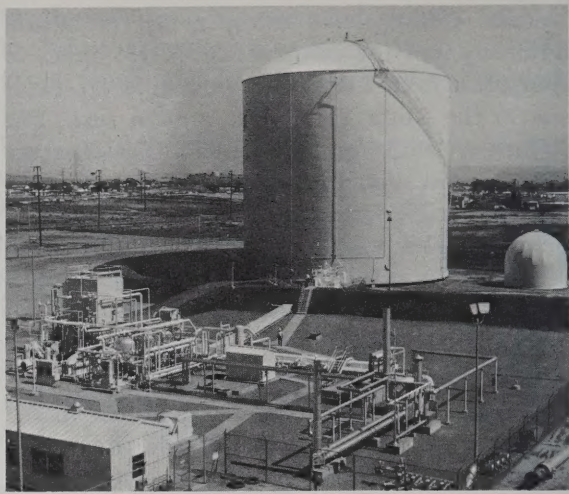


Figure 4.8—The San Diego Gas & Electric Company's LNG plant liquefies and stores natural gas at minus 258 degrees Fahrenheit. The 175,000 barrel storage tank holds the equivalent of 620 million cubic feet of natural gas.

In addition, Distrigas Corporation of Boston, Massachusetts, has applied to the Federal Power Commission for authorization to import up to 14 shiploads of LNG annually, approximately 15.4 billion cubic feet, from Algeria to its terminals in Everett, Massachusetts and Staten Island, New York. The rates to be paid by Distrigas f.o.b. U.S. port of delivery range from 68 cents to 85 cents per million Btu depending on the

month of delivery. The price is subject to an automatic escalation. At the time this report was written the Commission was considering the FPC examiner's initial decision in this case, issued June 14, 1971, which would grant the application as sought, subject to several conditions as to reporting procedures, financing, and the stipulation that the initial import price will be kept at 68 cents per million Btu.

Ocean Transport of Residual Fuel Oil

One of the principal reasons why residual oil has been able to maintain a strong competitive position among the fossil fuels is the relatively low cost of ocean transport. The increasing size and speed of tankers, improved loading and unloading facilities and navigational aids have helped keep the costs of ocean transport low.

In 1959, the average deadweight tonnage (load carrying capacity) of the world's tanker fleet used in the ocean transport of crude petroleum and petroleum products was 19,100 tons. The average size of ships under construction or ordered during that year was 37,800 deadweight tons. By the end of 1968, the average deadweight tonnage of the world's tanker fleet had increased to 33,700 tons; the average speed had increased from 14.8 knots in 1959 to 15.8 knots; and the average size of tankers under construction or ordered in 1968 was 104,500 deadweight tons. The larger ships built in recent years or under construction, however, are used primarily in long hauls of crude oil. Because of the relatively shorter hauls associated with the bulk of the residual fuel oil deliveries to this country from various points of origin in the Western Hemisphere, and because of draft limitations in East Coast ports, many of the tankers used for residual fuel oil transport are of the 30,000 to 40,000 ton class. These ships, generally engaged in a single commodity, shuttle type service, are usually equipped with steam coils to facilitate the removal of the residual fuel oil from the tankers.

Interfuel Competition

During the ten-year period, 1960 through 1969, electric utility demand for fossil fuels increased 90.6 percent (from 262.9 to 501.0 million tons of coal equivalent). During that period the average annual compound growth rate of fossil fuel demand by electric utilities was 7.4 percent. This growth was unevenly distributed among coal, gas, and oil in the various Census Regions of the country. Fuel consumption by electric utilities, 1960 and 1969, and average growth rates by Census Regions are shown in table 4.16.

While each of the fossil fuels finds some market in most of the states, individual fuels usually have a competitive advantage in any one region, with each region tending to have one dominant fuel. Except for non-economic considerations, such as government regulations, the choice of fuel for any one plant is normally

TABLE 4.16

Fuel Consumption by Electric Utilities, 1960 and 1969, and Average Growth Rates, by Census Regions

Region	COAL			GAS			OIL		
	Consumption in 10^6 Tons		Average Compound Growth Rate, Percent	Consumption in 10^6 Mcf		Average Compound Growth Rate, Percent	Consumption in 10^6 Bbls.		Average Compound Growth Rate, Percent
	1960	1969		1960	1969		1960	1969	
New England	5.9	5.0	−1.9	12.9	6.9	−6.7	16.1	60.2	15.8
Middle Atlantic	33.9	43.7	2.9	89.3	161.7	6.8	25.1	98.6	16.4
East North Central	69.8	118.0	6.0	61.4	166.3	11.7	1.3	3.8	12.7
West North Central	10.2	22.2	9.0	245.1	398.9	5.6	1.6	2.0	2.5
South Atlantic	27.2	63.8	9.9	147.4	268.1	6.9	14.2	56.9	16.7
East South Central	26.9	46.9	6.4	53.2	129.6	10.4	0.1	0.3	13.0
West South Central	*	*	*	656.7	1,571.6	10.2	0.3	0.5	5.8
Mountain	2.8	10.7	16.1	135.0	186.5	3.7	2.6	2.2	−1.8
Pacific	0.0	0.0	0.0	323.7	590.0	6.9	24.1	19.8	−2.2
United States Total (Contiguous)	176.7	310.3	6.5	1,724.7	3,479.6	8.1	85.4	244.3	12.4

* Insignificant.

based on a determination of which fuel results in the lowest cost of delivered electric power at the load center. In addition to the cost of fuel, such considerations as plant site and cooling water availability, fuel availability over a period of time, characteristics of the fuel supply market, magnitude and nature of fuel demand, proximity to transportation routes, regional variations in plant construction costs, transmission costs and availability of transmission rights-of-way, local tax structures, import restrictions, and environmental quality considerations, affect decisions on selecting the type and location of new generating stations.

All factors considered, about ten years ago coal had an advantage and, consequently, was the dominant fuel for thermal electric power generation in the New England, Middle Atlantic, East North Central, South Atlantic, and East South Central States. Similarly, gas was the dominant fuel in the West North Central, West South Central, Mountain and the Pacific States. In recent years, the interplays influencing fuel choices have changed, and some areas—particularly New England—have shown definite shifts in the patterns of fuel use. The role which each of the fossil fuels played in the electric power generation picture in 1960 and 1969 in the various Census Regions is shown in table 4.17.

Factors Affecting Interfuel Competition

Normally, historical data on the delivered price of fuels and estimates of future fuel prices provide an acceptable indicator for projecting interfuel competition. The technologies of electric power generation and transmission, however, are changing rapidly. Furthermore, the economic impact of the various factors affecting the delivered price of electricity, including environmental quality considerations, change significantly from plant site to plant site, so that regional and even State averages of prices which electric utilities paid for fossil fuels in the past fail to provide a reliable basis for projecting interfuel competition. It is possible, nonetheless, to examine some of the principal factors, evaluate their effect on interfuel competition during the past ten years, and to surmise the probable impact which these factors are likely to have on interfuel competition in the next two decades.

Air Pollution

The air pollution effects of the combustion of fossil fuels at electric generating stations are discussed in chapter 11.

High-Voltage Transmission

Improvements in high-voltage transmission generally tend to improve the competitive position of coal. It enables the development of inaccessible coal reserves and combustion of coal at the mine or at mid-point sites remote from densely populated load centers. On the other hand, this advantage is sometimes more than offset by the high costs of transmission right-of-way and the costs of minimizing the environmental impact of high voltage transmission lines.

TABLE 4.17

Fossil Fuel Use for Electric Power Generation by Census Regions, as a Percent of Total BTU, 1960 and 1969

Region	Coal		Gas		Oil	
	1960	1969	1960	1969	1960	1969
New England	58	23	5	2	37	75
Middle Atlantic	78	57	8	9	14	34
East North Central	96	93	4	6	....	1
West North Central	47	55	52	44	1	1
South Atlantic	77	70	15	13	8	17
East South Central	92	89	8	11	....	....
West South Central	....	....	100	100	....	....
Mountain	26	55	66	42	8	3
Pacific	....	....	68	83	32	17
U. S. Average	66	58	26	29	8	13

Transport Limitations

To date, transport limitations act primarily to impede the competitive position of residual fuel oil. Because of its relatively high viscosity, residual fuel oil cannot be economically moved by pipeline over long distances, and, therefore, its competition for the thermal electric market is limited to areas with cheap water transport facilities or to areas adjacent to petroleum refineries.

High-viscosity residual oil can be made to flow through longer pipelines if the pipelines are heated—a prohibitive cost item in most instances, although research is underway to improve the efficiency and effectiveness of pipe heating systems. Research is also underway, to develop a low-cost fuel additive which will lower the temperature at which residual oil will flow. Such developments would improve the competitive position of residual oil.

Nature of Fuel Demand by Electric Utilities

The average size of generating units being installed is constantly increasing. Because electric utilities require an assured long-range supply of fuel, and in the case of coal and oil, maintenance of substantial fuel stock piles for emergency use, the increasing average size of generating units has led to the following trends:

1. Long range contracting to assure a continuing supply of fuel and to take advantage of economies of scale in both fuel purchasing and transport.
2. Decreasing dependence on spot buying. Undoubtedly, some companies burning residual oil or coal will continue to buy spot fuel whenever the spot offer is below the firm contract price, or to strengthen their stock pile when the reserve becomes uncomfortably low. Generally, however, generating companies are expected to continue to decrease their dependence on spot purchases.
3. Increasing dependence on a single fuel in plant design and construction. Notable exceptions to this trend are plants in areas where off-peak gas is available at dump prices.

Characteristics of the Fuel Supply Market

In the period immediately following World War II the coal industry lost two major markets —the railroads and home heating—and was left with a great deal of excess capacity. Interfuel competition was keen and coal was readily available on relatively short notice to satisfy the electric power and other industrial demand. The post-war economic boom stimulated industrial coal consumption to the point that many small and inefficient mines sprang up. The operators of small mines soon found that they could not meet the competition, and the number of operating mines started to decline rapidly after reaching a peak of 9,429 in 1950. The number decreased to 7,719 by 1959, and to 5,118 by 1969. There is very little excess capacity in the coal industry today, and coal production is concentrating more and more in the large, modern mines of a relatively small number of coal mining companies, some of which are subsidiaries of complex industrial conglomerates.

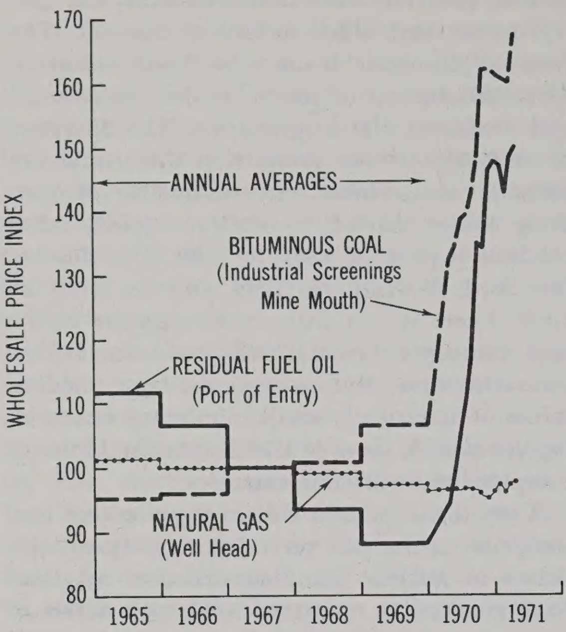
A rapid rise in total United States energy consumption in the past several years coupled with delays in nuclear plant construction programs have resulted in unprecedented high levels of demand for all fossil fuels, but uncertainities of future air pollution control requirements, coal mine health and safety regulations, and continuing labor problems have discouraged coal mine development. The industry and the railroads were not prepared, and a very tight coal delivery situation developed in the first half of 1970. This situation also served to magnify equally tight situations in natural gas and residual oil supply. Consequently, fossil fuel prices increased significantly. The magnitude of the recent price increases is reflected in figure 4.9, showing the relative changes in the wholesale price index of fossil fuels (deflated by the Industrial Commodities Wholesale Price Index).

Much of the electric utility fuel demand for new, large coal-fired units can be met only by opening new mines. Because of the high investment costs associated with the opening of new mines, coal mining companies frequently insist on long-term supply contracts.

A serious question of future gas availability for electric power generation has recently arisen in the natural gas industry, particularly where interstate commerce subject to Federal Power Commission regulation is involved. The gas reserve-to-production (R/P) ratio has been continually declining since the end of World War II. In 1946 the R/P ratio was as high as 32.5 to 1.

RELATIVE CHANGES IN THE WHOLESALE PRICE INDEX OF FOSSIL FUELS

Deflated by the Industrial Commodities Wholesale Price Index (Index 1967=100)



Bureau of Labor Statistics Data

Figure 4.9

This ratio had declined to 26.9 to 1 in 1950, to 20.2 to 1 in 1960, and to 11.9 to 1 in 1970.

Gas producers contend that the declining R/P ratio is a reflection of the critical gas supply situation and that any significant limitation on contract prices (for gas sold in interstate commerce) would necessarily result in a dampening of essential exploration and development activity which, in turn, will lead to a continuing decline in the finding-to-production and reserve-to-production ratios.

Many producers claim that their uncommitted reserves, including potential reserves, are already too small to meet the projected demands of new, large generating units and there is a growing reluctance on the part of the gas industry to make long range commitments to the electric power industry, particularly where interstate commerce subject to Federal Power Commission regulation is involved. For this reason, it appears that the greatest potential for the growth of natural gas consumption for electric power generation in the foreseeable future exists in the West South Central States—the area where most of the Nation's gas is being produced and where it can be delivered to power plants in intrastate commerce.

At present there is great upward pressure on the price of natural gas. As the price of natural gas (and that of other fossil fuels) increases, imported natural gas, including LNG, and synthetic, high-Btu gas from coal may become increasingly competitive with domestic natural gas, particularly on the East and West coasts and in areas adjacent to low-cost coal.

At the present time imported residual fuel oil competes favorably with domestic fuels. As long as oil companies continue to make most of their profit from sales of refined products, it is reasonable to expect that the supply of residual fuel oil will become more limited in the years ahead as foreign producers tend to follow the United States trend toward a higher degree of crude oil refining.

International Trade

Three important aspects of international trade in residual fuel oil and LNG need to be considered in projecting future supply of these fuels for the electric power industry:

1. The growing world competition for primary energy resources;
2. The effect which growing fuel imports will have on this Nation's balance of trade; and
3. The question of national security, i.e., how dependent can we afford to become on foreign sources of primary energy supply for electric power generation?

Regional Outlook

It is most difficult to predict how the aforementioned elements will intermix to affect competition among the fossil fuels; what elements may cease to have any significant bearing on inter-fuel competition; what new elements may emerge to alter the entire competitive picture; or how the various elements will combine to strengthen the competitive position of a particular type of generation in any one region. On a national scale it is expected that by 1990 nuclear fuel will be the major single source of primary energy for electric power generation. The inroads which nuclear fuel is making will result in a rapid decline in the compound an-

nual growth rate of fossil fuel demand from an average 7.5 percent during the 1961–1970 period to an estimated average 3.7 percent during the seventies and 2.7 percent in the eighties.

Many of the elements discussed above were already exerting some influence on the competitive position of the three major fossil fuels during the ten years from 1960 to 1969. Table 4.16 reflects the changes in fossil fuel demand which took place during that period in the various census regions of this country as a result of these influences. Barring any major, unforeseen breakthroughs in the technologies of electric power generation and transmission, and any significant shifts in the roles which the competitive elements play, it appears that some of the developing trends will continue into the foreseeable future.

In the New England states residual oil consumption for electric power generation has been growing at a higher rate than the national average while the use of coal decreased slightly and the use of gas declined significantly. Residual oil has emerged as the dominant fuel and it appears that it will continue in that role for some time.

In the Middle Atlantic States residual oil experienced a much higher rate of growth than either coal or gas. It appears that primarily because of air pollution control regulations the use of low-sulfur residual oil will continue to assume an ever increasing role in the fuel supply picture of that area. Coal, however, probably will remain the principal fossil fuel in western Pennsylvania and western New York.

Although some residual fuel oil will be utilized in the East North Central Region, coal will continue to account for the bulk of the fossil fuels used for electric power generation in that area. The absolute growth of the use of this fuel will depend to a large measure on the successful development of satisfactory methods for preventing the sulfur contained in the coal from finding its way into the air.

Coal and natural gas share about equally in the electric utility market of the West North Central States, although a slight movement in favor of coal is apparent. Because of the generally low level of fuel consumption in the West North Central States, the projected use of low-sulfur-bearing North Dakota lignite in several relatively large plants should result in a continued increase in the use of coal in that area. Gas will continue to be an important source of energy in Kansas and Nebraska.

Except for Florida, where residual fuel oil is and, will probably continue to be the single largest fuel used for electric power generation, the remainder of the South Atlantic Region is heavily influenced by the Appalachian coal industry. Although the demand for gas and low-sulfur residual oil will continue to be strong, coal will most likely maintain its dominant position in that area.

In part because of environmental considerations the rate of growth of natural gas demand will probably continue to be greater than that for coal in the East South Central Region. Nonetheless, total consumption of gas will remain at a relatively low level as it is of major importance only in the State of Mississippi. The other three states of the Region—Alabama, Kentucky, and Tennessee—have substantial indigenous resources of coal and in those states coal will continue to dominate the electric utility market.

The West South Central Region including the offshore areas, is the origin of 80 percent of the country's current production of natural gas. Practically all the thermal power generated in the region is based on this fuel and gas is expected to remain the principal fuel for this purpose in the two decades ahead. The growth of natural gas demand in this area will also account for most of the national growth in gas demand for electric power generation during the next twenty years.

The Mountain States with vast coal resources which include large reserves of relatively low-cost, low-sulfur coal, have begun to exploit these resources on an increasing scale to generate electricity not only for their own needs but also for the needs of the Pacific and Central States. Starting from a relatively low base, consumption of coal in the Mountain States for electric power generation grew at the phenomenal rate of 17 percent annually during the 1960–1969 period. Coal has replaced natural gas as the leading power plant fuel in the area and is expected to continue to strengthen its dominant position. It appears that the Mountain States will continue to be the major source of coal for the electric power generating needs of the entire West.

Natural gas is the principal fossil fuel in the

PROJECTED FOSSIL FUEL REQUIREMENTS FOR ELECTRIC POWER GENERATION BY REGIONS

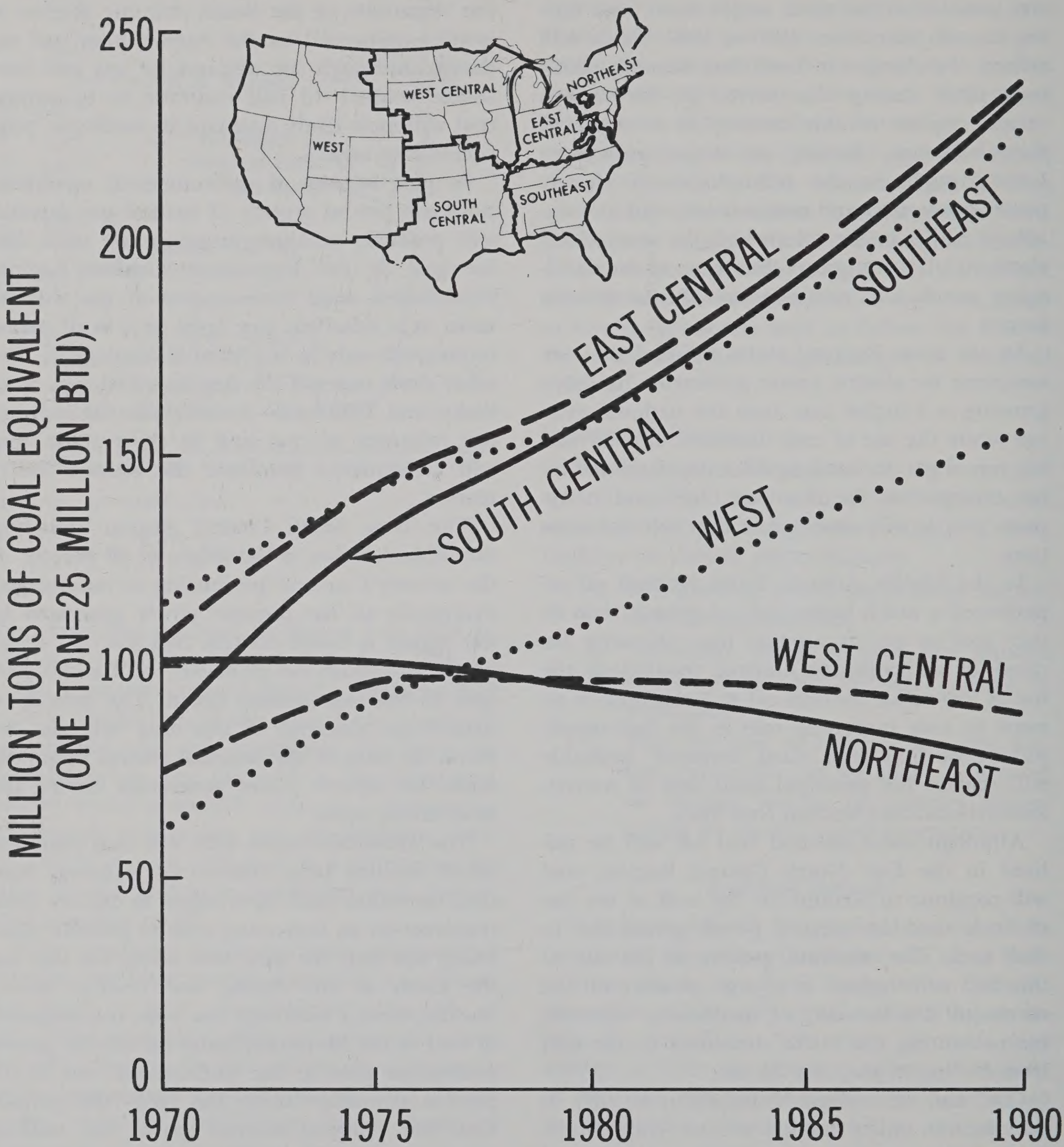


Figure 4.10

Pacific States. Practically all of the gas, however, is consumed in California where stringent air-pollution control regulations provide a favorable competitive climate for this fuel.

The use of fossil fuels for electric power generation in the Pacific Northwest has been negligible in the past. A large coal-fired plant under construction in the State of Washington will alter this picture, but not enough to make a significant change in the dominant position which gas will maintain in the entire Pacific area.

The projected fossil fuel requirements for electric power generation by National Power Survey regions, are shown in figure 4.10.

Regulations for air pollution and thermal effects will become increasingly important in the future and could lead to some modifications of the trends indicated in this chapter and on the chart.

CHAPTER 5

FOSSIL-FUELED STEAM-ELECTRIC GENERATION

Introduction

Fossil-fueled steam-electric power plants long have been the mainstay of the electric power industry. They currently account for about 76 percent of total generating capacity and more than 80 percent of total generation. With increased reliance on nuclear power, they are expected to account for only about 44 percent of both capacity and generation by 1990. Nevertheless, the total capacity of these plants is expected to increase from 259,000 megawatts in 1970 to 390,000 megawatts in 1980, and 558,000 megawatts in 1990. The total installed fossil-fueled steam-electric capacity from 1920 to 1970, with projections to 1990, is shown in figure 5.1.

FOSSIL - FUELED STEAM - ELECTRIC GENERATING CAPACITY
Contiguous United States

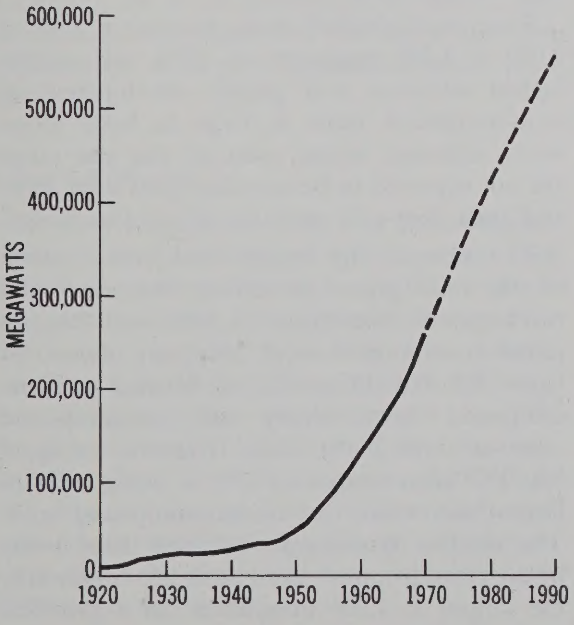


Figure 5.1

The report of the Commission's Technical Advisory Committee on Generation, entitled "The Generation of Electric Power," and published in Part IV of this Survey, includes a comprehensive presentation on the past, present, and probable future position of fossil-fueled steam-electric generation in the total power supply of the contiguous United States. Statistical and other pertinent information on thermal plants are included in the annual publication of the Federal Power Commission entitled "Steam-Electric Plant Construction Cost and Annual Production Expenses."

This chapter summarizes data on fossil-fueled steam-electric plants and discusses those aspects of fossil-fueled steam-electric power supply which relate to its progress and its potential limitations.

Engineering criteria concerned with supplies of cooling water, adequacy of fuel supply, fuel delivery and handling facilities, and proximity of load centers have always been important factors in the selection of power plant sites. More recently, however, environmental factors have gained in influence and now often dominate in the selection of sites.

Environmental problems involved in power plant siting include the discharge of objectionable gases and particulates to the atmosphere, the rejection of waste heat to natural bodies of water, the discharge of chemical and sanitary wastes, and esthetic considerations. These matters are discussed in chapters 10, 11 and 12.

Historically, the improvements in steam-electric generating units have been fairly continuous and adequate to meet the needs of the electric utility industry. Although nuclear-fueled and gas-turbine-driven generating units have attracted more attention from the technical press and the public during recent years, there have

been substantial advances in conventional fossil-fueled steam-electric power supply technology.

The major progress in conventional fossil-fueled steam-electric generation during the past decade has been increases in unit size, reduction in manpower requirements per unit of capacity, automation, better recording of operating data, and improvement in operating reliability of auxiliaries. Reductions in fossil-fueled steam-electric production costs per kilowatt-hour were significant until about the end of 1966, despite continuing inflation. Since that time, however, increases in construction and operating costs have more than offset the gains made through technological improvements.

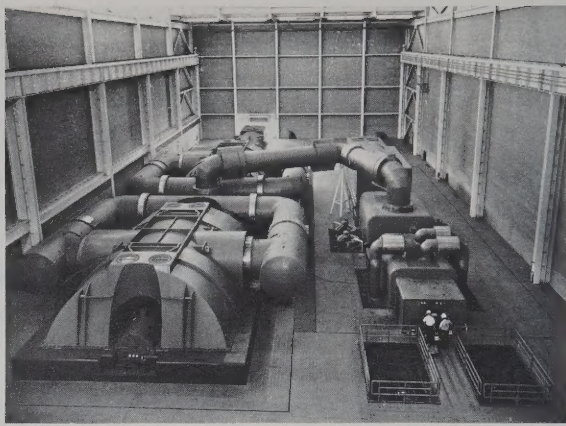


Figure 5.2—This 1,150-MW unit at TVA's Paradise Steam Plant was the largest generating unit in service in the United States in 1970.

Sizes of Units

In 1930, the largest steam-electric unit in the United States was about 200 megawatts, and the average size of all units was 20 megawatts. Over 95 percent of all units in operation at that time had capacities of 50 megawatts or less. By 1955, when the swing to larger units began to be significant, the largest unit size had increased to about 300 megawatts, and the average size had increased to 35 megawatts. There were then 31 units of 200 megawatts or larger. By 1968, the largest unit in operation was 1,000 megawatts; there were 65 units in the 400 to 1,000 megawatt range; and the average size for all operating units had increased to 66 megawatts. In 1970, the largest unit in service was 1,150 megawatts; three 1,300-megawatt units were under construction; and three additional 1,300-megawatt units were on order. The average size of all units under construction was about 450 megawatts. As the smaller and older units are retired, the average size of units is expected to increase to about 160 megawatts by 1980 and 370 megawatts by 1990.

Capital costs per kilowatt and operation and maintenance costs per unit of energy generated are less for large units than for small ones. This creates incentives to install larger units which will continue until, at some size and some point in time, the incremental savings may be offset by added physical or operational problems. This point is not expected to be reached, particularly for large utilities or those operating in pools, until sometime after 1990. While experience with large units to date has shown some increase in maintenance costs and reduction in unit availability, this is to be expected with prototype units, and the problems should be overcome as later generating units are placed in service.

The maximum size of conventional 3,600 revolutions per minute (r/min), single-shaft generating units expected to be in service by 1980 is approximately 1,500 megawatts. While increases beyond that may occur, it is not expected that the size of high-pressure, high-temperature, single-shaft turbine-generators will exceed 2,000 megawatts by 1990.

Some multiple-shaft units may reach sizes of 2,000 to 2,400 megawatts by 1990, and technological advances may permit development of cross-compound units as large as 3,000 megawatts, although initial units in this size range are not expected to be installed until after 1990, and then they will probably be nuclear fueled.

The sizes of the largest fossil-fueled steam-electric units placed in service since the initial two-megawatt installation in 1900, and the projected maximum sizes to 1990, are shown on figure 5.3. No differentiation between tandem-compound (single shaft) and cross-compound (two or three shaft) units is shown on figure 5.3. The cross-compound unit is being built in larger sizes than the tandem-compound unit. The smallest cross-compound unit listed today in the manufacturer's catalogs is 250 megawatts; the largest is 1,500 megawatts. As a practical matter, very few cross-compound units of less

LARGEST FOSSIL-FUELED STEAM-ELECTRIC TURBINE-GENERATORS IN SERVICE
1900 - 1990

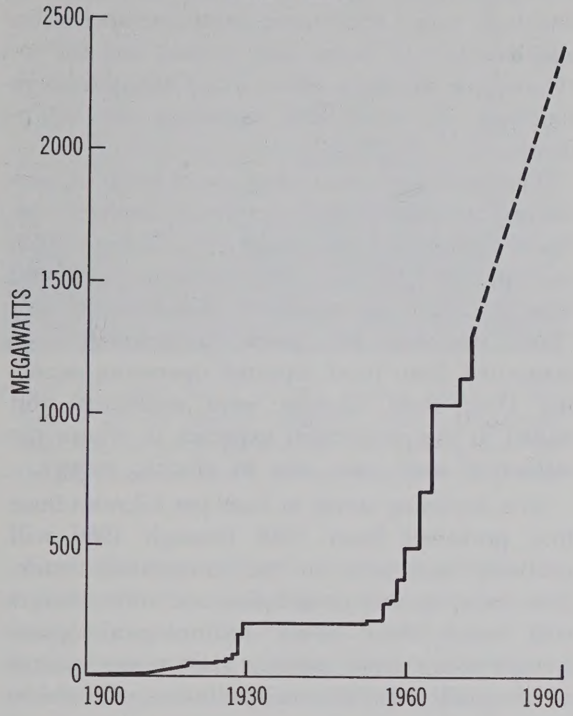


Figure 5.3

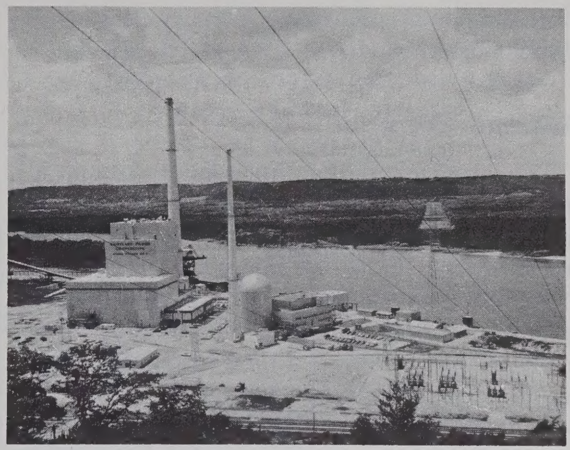


Figure 5.4—Dairyland Power Cooperative's Genoa plant south of La Crosse, Wisconsin, has a 350-MW coal-fired unit and a 50-MW boiling water reactor unit.

than 800 megawatts are being ordered because the tandem-compound units are generally more economical in the smaller sizes. The present maximum size of tandem-compound units is approximately 800 megawatts, but larger sizes are expected to accompany improvements in technology.

Sizes of Plants

In 1948 there were only two steam-electric plants in the United States with capacities over 500 megawatts—the 881-megawatt, 12-unit, Hudson plant and the 630-megawatt, 9-unit, Hell Gate plant, both in New York City. Fifteen years later, in 1963, TVA's 9-unit, 1,700-megawatt, Kingston plant was the largest. In 1970, the largest was TVA's 3-unit, 2,558-megawatt, Paradise plant. By 1973, the 4-unit, 3,200-megawatt Monroe plant of Detroit Edison Company, now under construction, will be the largest plant. Some 12 plants will have capacities over 2,000 megawatts by 1975.

The economic advantage of size for individual units also applies to plant sizes. The cost of the components of a plant that are little affected by the number of units, such as office space, shops, docks, and landscaping, can be spread over more capacity. Coal handling equipment, cooling facilities, and other appurtenances can also be operated at less cost per kilowatt-hour at larger installations. The problems of site acquisition and development may be less severe for one large site than for two or more smaller ones. These and other advantages of large installations suggest that plant sizes will continue to increase during the years ahead.

There are factors, however, that tend to limit plant sizes. For example, the amount of land required for a coal-fired plant increases with capacity principally because of requirements for coal storage, ash disposal, and cooling ponds or towers, if required. The amount of land and water required for large plants will preclude the use of many otherwise desirable plant sites. Environmental problems tend to be greater for large plants, and public reactions may limit the amount of capacity that will be permitted at any one location. Plant size is also a factor to be considered from the standpoint of reliability, and there is an important relationship between the maximum size of plants and the capability of system interconnections.

On balance, the advantages of larger plants seem to outweigh the disadvantages. It is expected that plants having 5,000 megawatts of capacity will be in service by 1980, and that by

1990 maximum plant sizes may be as high as 10,000 megawatts.

Average Costs

The average original investment cost of all steam-electric generating capacity in service and operated by Class A and B privately owned electric utilities is shown on figure 5.5 for the years 1950 through 1969. This chart indicates that, despite continuing inflation, the average investment cost per kilowatt of total installed generating capacity decreased during the 1960–1968 period. Price inflation, higher labor costs, increased investment in environmental protection equipment, and a rapidly increasing demand for facilities caused a sharp reversal of this trend, beginning in 1969.

Larger generating units, outdoor type construction where feasible, and unit type construction (one boiler per turbine-generator), have been the principal contributing factors to lower capital costs per kilowatt of capacity. Other factors that have helped to reduce unit costs include: an increase in the number of large single shaft units, reduced weight per megawatt of turbine-generator capacity, standardization of design of major equipment items, prefabrication and assembly of boiler tube panels, and the increased use of heavy construction equipment in building the plant and installing the equipment.

The estimated cost per kilowatt-hour of producing steam-electric energy is depicted by figure 5.6 for each year from 1946 through 1969, and for 1940, the last full year prior to World War II. The "Operation and Maintenance" and "Fuel" expenses are based on recorded costs computed from total reported operating expenses. Unit fixed charges were estimated and added to the production expenses to obtain the estimated total unit cost of electric energy.

The declining trend in costs per kilowatt-hour that prevailed from 1959 through 1966 will probably not recur in the foreseeable future. Cost increases due to inflation and other factors will more than offset technological gains. Longer construction periods and greater control of air quality and thermal pollution will add to future costs.

AVERAGE INVESTMENT COST PER KILOWATT OF TOTAL INSTALLED STEAM-ELECTRIC CAPACITY

Class A & B Privately-Owned Utilities

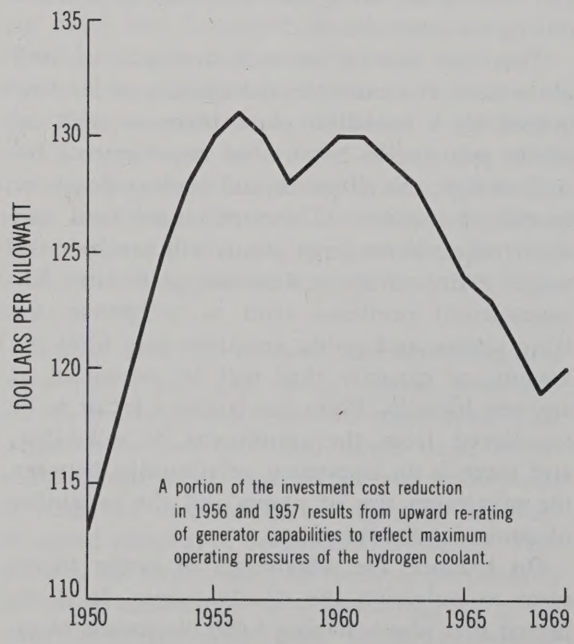


Figure 5.5

TOTAL COSTS OF PRODUCING STEAM-ELECTRIC POWER

Class A & B Privately Owned Utilities

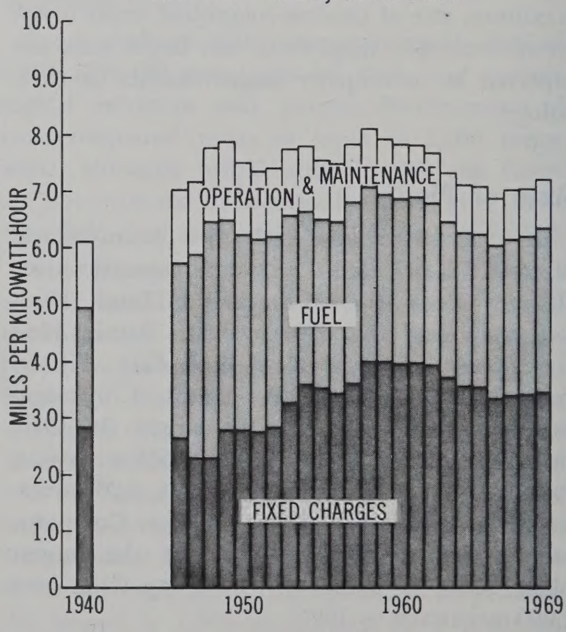


Figure 5.6

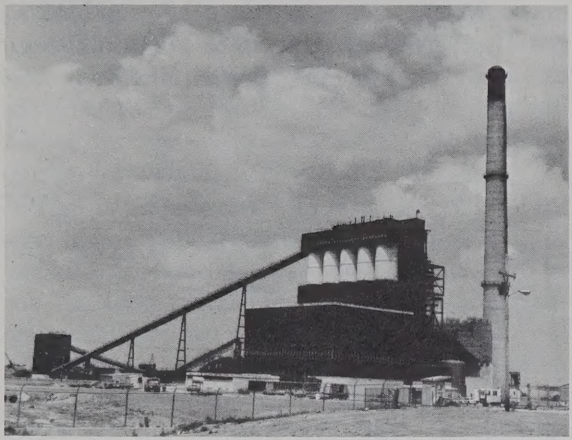


Figure 5.7—Unit No 1 in the Asbury plant of The Empire District Electric Company. Coal is transported from mine to plant by conveyor, and cooling water for the 200-megawatt unit is pumped from four deep wells.

Centralized control and increasing automation of plant operations are expected to permit some reduction in the number of plant employees per megawatt of capacity. Other factors tending to reduce manpower requirements are the ever-increasing unit and plant sizes and modernization and mechanization of fuel handling equipment and facilities. Figure 5.8 shows graphically the reduction in manpower requirements per megawatt of capacity as unit size and number of units increase. On the other hand, higher labor costs may negate the manpower savings. By 1990, technical personnel, including those on shift assignment, are likely to require the equivalent of a bachelor's degree to qualify for employment in the highly sophisticated plants that will then be operating, whereas in the past, operating and maintenance personnel have been craftsmen whose skills were developed largely through on-the-job training and experience.

Lower fuel costs during the last decade were due to competition among the suppliers of fossil fuels, adoption of mechanized and strip coal mining, more economical methods of transportation, and improved efficiency of generating plants. The entry of nuclear-fueled generating capacity on an economic basis has introduced an alternative source of power to compete with fossil-fueled electric generation. Despite this, beginning about mid-1969, the cost of fossil fuels for steam-electric power plants has increased substantially. This has been due in part to coal

MANPOWER REQUIREMENTS FOR OPERATION AND MAINTENANCE OF MODERN COAL-FIRED AND GAS-FIRED STEAM-ELECTRIC PLANTS

(1955 to 1969 Installations)

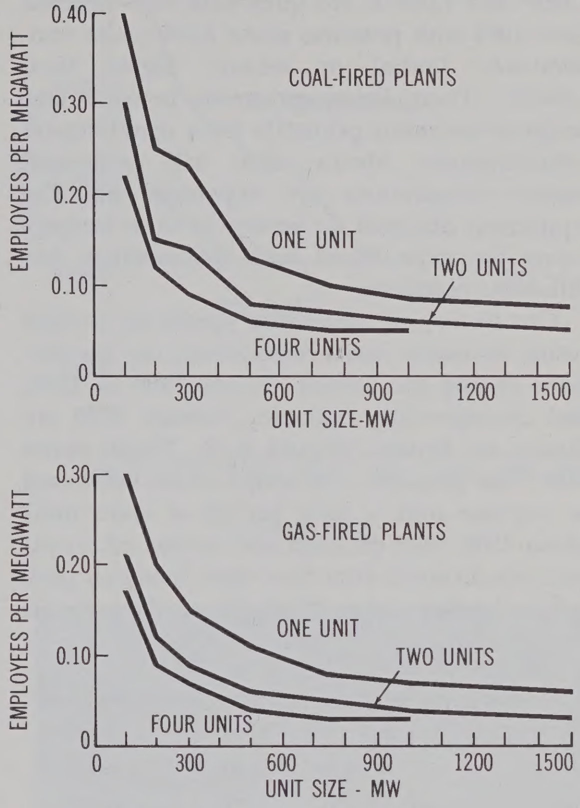


Figure 5.8

shortages resulting from underestimated demand and increased foreign exports of U.S. coal, and delay in completion of nuclear units. Other important factors have been the enactment of air quality standards, requiring the use of more expensive low-sulfur fuels, higher transportation costs associated with obtaining such fuels, dislocations of transportation equipment sometimes necessitating costly alternative transportation arrangements, and increased mining costs attributable to the Federal Mine Health and Safety Law which became effective April 1, 1970.

Steam Conditions

Since 1964 turbine throttle steam conditions for large new generating units have been relatively constant, with pressures up to 3,500 psi and Fahrenheit temperatures of 1,000° initial

356-238 O - 72 - 9

and 1,000° reheat. Although some large 2,400 and 2,600 psi units are on order, the 3,500 psi units predominate in sizes of 500 megawatts and larger. A few double reheat generating units have been built with reheat temperatures of 1,025° and 1,050°F. No units have been ordered since 1964 with pressures above 3,500 psi or temperatures (initial or reheat) higher then 1,050°F. These limits on steam pressure and temperature result primarily from metallurgical considerations. Metals that will withstand higher temperatures are expensive and the equipment designed for service at those temperatures has experienced both maintenance and reliability problems.

The history of maximum operating turbine steam pressures and temperatures on installations during the 69-year period, 1900 to 1968, and corresponding estimates through 1990 are shown on figures 5.9 and 5.10. These charts show that pressures and temperatures continued to increase over a long period of years until about 1960, then declined and leveled off, as experience dictated, after that time. Based on present technology, the relatively small gain in efficiency in changing from 3,500 to 5,000 or even 6,000 psi and from 1,050°F. to 1,200°F. is not sufficiently large to justify the substantial additional capital and annual expenditures necessary to install and maintain equipment made of metals required for these steam conditions. Improved metals should be available during the next decade and they may induce some increase in pressures and temperatures. Major increases, however, are not anticipated.

MAXIMUM DESIGNED THROTTLE PRESSURES OF TURBINES INSTALLED EACH YEAR

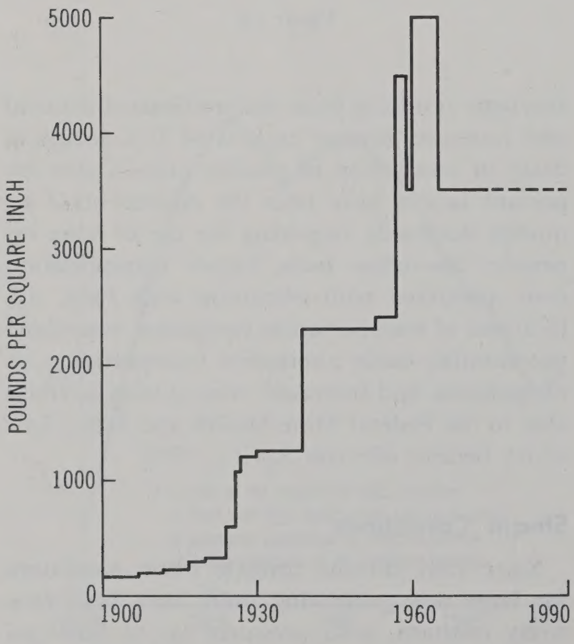


Figure 5.9

MAXIMUM DESIGNED THROTTLE TEMPERATURES OF TURBINES INSTALLED EACH YEAR

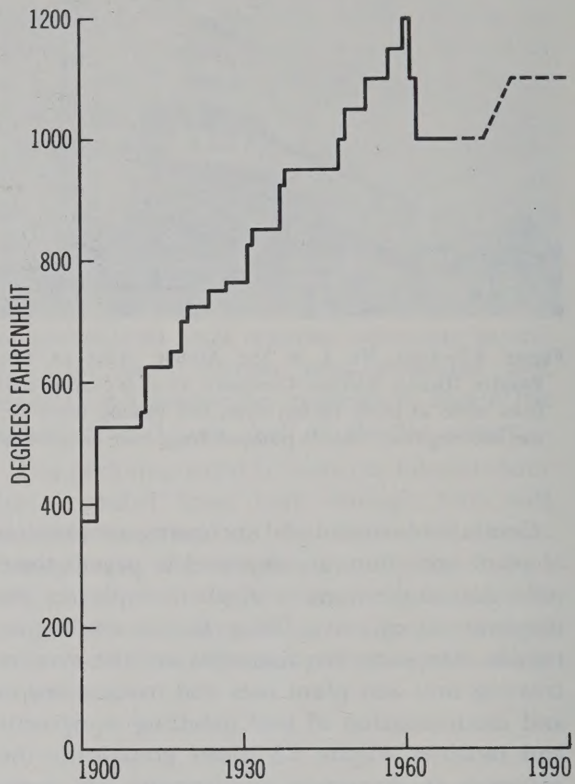


Figure 5:10

Heat Rates

Heat rate, as the term is used in the electric power industry, is the amount of heat input in British thermal units (Btu) required to produce a net output of one kilowatt-hour of electrical energy. Until improved alloys are developed to permit higher steam pressures and temperatures, the rate of decline in average heat rates will not be as rapid as in the past. Recent improvements

in both turbines and boilers, apart from steam conditions, have contributed to somewhat lower heat rates, and increases in unit size have also provided some advances, but better metals and higher throttle temperatures offer the best potential for further major improvements.

The national record annual operating heat rate for a turbine-generator unit is 8,534 Btu per kilowatt-hour. It was established in 1962 by the Philadelphia Electric Company's 350-megawatt Eddystone No. 1 — a 5,000 psi, 1,200°/1,050°/1,050°F., double reheat unit. This is the first and only 5,000 psi, 1,200°F. unit in service in the United States. In its ten years of operation, its availability has been somewhat less than expected and the annual heat rate has varied from the low of 8,534 Btu in 1962 to a high of 8,874 Btu in 1967. The best annual heat rate for a 3,500 psi, double reheat unit was achieved by Eddystone No. 2, the same size as No. 1, also in 1962—8,633 Btu per kilowatt-hour. This unit was placed in service in late 1960. The Eddystone record was bettered in 1969, on the basis of a partial year of its initial operation, by Duke Power Company's Marshall No. 3 unit with a heat rate of 8,617 Btu/kilowatt-hour for about 4,600 operating hours. The unit continued high performance operation in 1970 with a heat rate of 8,638 Btu/kilowatt-hour for the full year. Most of the lowest annual heat rates have been achieved by cross-compound units, but the Marshall No. 3 unit is tandem-compound, with 1000°/1000°/1000°F double reheat.

Figure 5.11 shows that heat rates for the most efficient fossil-fueled steam-electric stations decreased markedly until 1950, and then leveled off. Projected heat rates are shown through 1990. National average annual heat rates will continue to decline as new generating capacity with low heat rates is installed and older, less efficient capacity is retired. The decline may be slowed, however, by the types of fuels which must be burned to meet air quality standards.

Base Load Units

All of the high-pressure, high-temperature, fossil-fueled steam-electric generating units, 500 megawatts and larger, have been designed as "base load" units and built for continuous operation at or near full load. Daily or frequent "stops" and "starts" are not consistent with their design and construction and so-called "cycling" or part-time variable generation was not originally comtemplated for these units. However, by the time units having lower incremental production costs become available for base load operation, it is believed that the earlier "base load" units can be adapted and used as

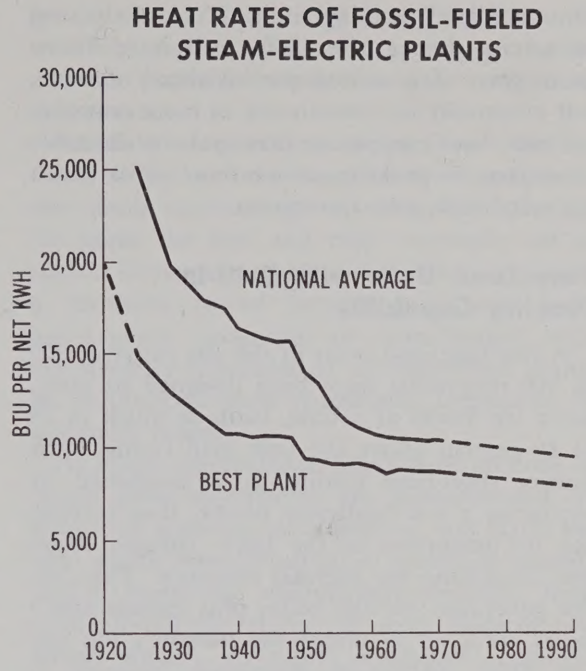


Figure 5.11

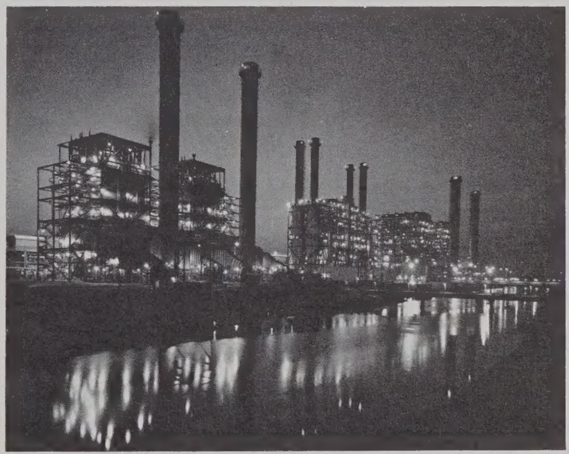


Figure 5.12—The 1,606-megawatt Haynes plant of Los Angeles Department of Water and Power, at Seal Beach, California, has six units and uses gas and oil for fuel. Pacific Ocean water is used for condenser cooling.

"intermediate" peaking units. The units placed in service during the 1960's still have 15 or more years of base load service ahead of them, but eventually the installation of more economical base load equipment may make it desirable to convert to peaking service those units which are suitable for such conversion.

Base Load Units with Built-In Peaking Capability

A few base load units in the size range of 200 to 400 megawatts have been designed to carry, for a few hours at a time, loads as much as 25 to 30 percent above the base load rating. Such greater short-time loading is accomplished by bypassing a top feedwater heater, thus increasing the steamflow in the lower turbine stages and decreasing the thermal efficiency. The electric generator and the boiler plus various auxiliaries are sized to match the turbine's top rating. The additional short-time capacity is obtained at a capital cost somewhat less than that for a conventional steam peaking unit. Operation at loadings in excess of the base load rating results in a substantial increase in the overall heat rate of a unit. A 350-megawatt unit of this type has been operating since 1964 in the North Lake plant of Dallas Power and Light Company. Other units of this type have been constructed and additional units probably will be built in isolated cases, but they are not expected to provide a significant portion of total requirements for peaking capacity.

Peaking Units

Steam-electric peaking units, sometimes referred to as mid-range peaking units, are designed for minimum capital cost and to operate at low capacity factor. They are oil- or gas-fired, with a minimum of duplicate auxiliaries, and operate at relatively low pressures, temperatures, and efficiencies. They are capable of quick start-ups and stops and variable loading, without jeopardizing the integrity of the facilities. Such units are economical because low capital costs and low annual fixed charges offset low efficiency and operation at low capacity factors. The units can, however, be operated for extended periods, if needed, to meet emergency situations.

The first of such fossil-fueled steam-electric peaking units, a 100-megawatt, 1,450 psi, 1000°F., non-reheat, gas-fired unit, was installed in the Arsenal Hill plant of Southwestern Electric Power Company, at Shreveport, Louisiana, in 1960. Two earlier low capital cost fossil-fueled steam-electric plants—the 69-megawatt, single-unit Bird plant of the Montana Power Company (1952), and the 313-megawatt, two-unit Martins Creek plant of Pennsylvania Power and Light Company (1954)—were generally classified as hydro standby; they were not straight peaking installations. The Martins Creek plant was later modified for base load operation.

With increasing loads and the accompanying need for additional peaking capacity, at least 27 peaking units of this general type were on order or under construction at the end of 1970. All are either oil- or gas-fired, because the added costs of coal and ash handling facilities for peaking units are not justified by the small fuel cost saving that might be realized by using coal Eight of the 27 units are in the 250- to 350-megawatt class, fifteen in the 400-megawatt class, and four in the 600-megawatt class. Most of the units are designed for steam conditions of 1,800 psi and 950°/950°F.

The size of peaking units being installed is generally from five to ten percent of system capacity. If this pattern is to prevail for the larger systems of the future, peaking units of 1,000 megawatts capacity, or more, could be utilized. Existing technology is adequate to permit design of such units, but new applications of the technology will be necessary. For example, the problems associated with the need for steam temperature control suggest the possibility of multiple furnace installations with separately fired control surfaces. These and other problems are solvable, and it is expected that steam peaking units in all size ranges will gain in prominence, particularly in areas where hydroelectric potentials are limited.

Some foreign manufacturers have built peaking units using variable pressure boilers which are reported to have rendered satisfactory cyclical service.

Changing Operational Patterns for Older Units

The 25- to 100-megawatt generating units in the 650 to 1,250 psi, 650° to 900°F., pressure-

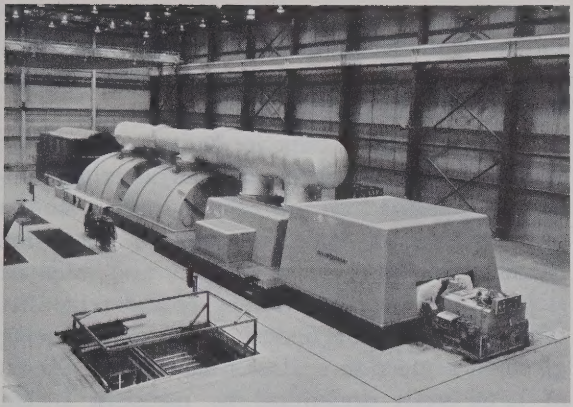


Figure 5.13—Turbo-generator in the Allegheny Power System's Fort Martin mine-mouth plant.

temperature ranges installed from 1930 to 1950 have been sturdy, dependable, and long-lived. With larger generating units coming into service, many of these older units, especially those of 50 megawatts and larger, are being modified to serve the upper part of the daily load curve. These older units do not have the quick startup characteristics of gas turbine peaking units and they were not designed for automatic operation. Nevertheless, they are available and can operate a few hours per day for peaking and at other times for "hot" reserve, ready to take on load when required.

In several cases where such older units are assigned to peak load service, coal-fired boilers have been converted to oil or oil-gas firing to reduce operation and maintenance labor costs. Maintenance costs are an important factor in determining the extent and type of use to be made of such older units.

During the last half of the 1970's and into the 1980's, the changeover from many hours of continuous generation to a few hours of use with daily or weekly starts and stops will probably be extended to include the 125- to 200-megawatt units installed from 1950 to 1960, or later. This group will include the reheat units with pressures of 1,450 to 2,400 psi and temperatures of 950° to 1,000°F. To make them useful as well as environmentally suitable for such changed operations, modifications and adjustments will need to be made in the units.

Maintenance

Power plant equipment represents a large investment and is expected to have a very high degree of service availability during its 30 to 40 year life. Such performance is not attainable without periodic inspections and continuing maintenance.

Scheduled equipment inspections identify worn, faulty, or otherwise defective equipment that needs overhauling, repairing, or replacing. To make the best and most economic use of sources of power supply, and to reduce exposure to excessive forced outages, scheduled plant maintenance programs are coordinated with maintenance schedules of all important plants on an interconnected system and, frequently, in adjoining systems.

At newer installations, physical inspections of power plant equipment are supplemented by automatic scanning, data logging, and alarm devices which identify actual or potential trouble points. Preventive maintenance resulting from such surveillance eliminates some failures and forced outages. As more experience is gained with scanning and logging equipment, it is expected to provide an improved basis for establishing the optimum period between physical inspections.

Use of contract maintenance for major items of equipment, particularly boilers and turbine-generators, is increasing. Most manufacturers have expert maintenance crews at strategic locations throughout the country. These crews are available to inspect and service equipment on a regularly scheduled basis. There are also independent maintenance firms which specialize in such work. An example of an arrangement for such maintenance is the agreement between the "Keystone Plant Owners Group" and the boiler supplier for the two 820-megawatt Keystone units in Pennsylvania. The agreement provides for an annual boiler inspection and for any necessary repairs and overhauling. The maintenance work is scheduled using the "Critical Path" method—a method which provides a systematic means of scheduling items of work so that the completed task is accomplished in a minimum time.

Present experience with large coal-burning steam-electric power plants indicates that 55 to 65 percent of total maintenance expense concerns the boiler plant. Annual maintenance expense on turbines and generators ranges from 15 to 25 percent of total plant maintenance costs. Some increased maintenance and repair work is

associated with very high temperatures and their effects on metals and alloys used in the boiler and the turbine. Because of corrosion and erosion from sulfur compounds and fly ash, coal-fired boilers usually require more maintenance than oil- or gas-fired boilers. In addition, maintenance is required on coal and ash handling facilities, both of which are subjected to rough, heavy duty. There are sometimes added boiler maintenance problems at plants which are converted to burn low sulfur coal, because the boiler systems were designed to work best with coal having other physical and chemical properties.

The problems of scheduling maintenance become more pronounced as larger units are installed, areas of coordinated operation are expanded, secondary system peaks increase, and system load factors improve. Timely and thorough maintenance is essential for system reliability. Some of the difficulties encountered in meeting loads during recent years were attributable, in part, to the fact that planned maintenance was postponed because of capacity deficiencies due to delays in service dates of new equipment, or perhaps in some cases incompletely carried out because of the need to restore units to service.

Performance of New Units

The performance of a generating unit may be rated in terms of its availability for service and its efficiency of operation. The availability for service is usually measured by scheduled and unscheduled outages. The availability of new, larger units with higher operating steam pressures and temperatures has, in general, not been as good as the availability of earlier units. The first of the units in this general category was placed in operation in 1957. Because of the relatively short in-service records of these large, modern fossil-fueled boiler and matching turbine-generator units, with highly complicated control systems and auxiliary equipment, neither their maintenance requirements nor their scheduled and unscheduled outage rates have been firmly established. The so-called "shakedown" period for some of these very large generating units has within recent times been as long as three to five years. It is during this period that initial operating problems are resolved to make the units dependable performers. Current judgment is that the average service life of these very large units will be about 30 years, including the "shakedown" period.

While experience data are being accumulated, manufacturers, utilities, and engineering consulting organizations are cooperating in studies and analyses of forced outages to determine causes, probability of recurrence, and essential steps to improve the availability and reliability of large units. Particular attention is being given to protection against unnecessary tripouts of large units occasioned by transient system instabilities. Some malfunction or untenable condition in a boiler is the most frequent cause of forced outages of generating units. Problems in the turbine-generator are the next most frequent cause. These may include an overheated bearing, water induction into the turbine, low oil pressure, control malfunctions or, in an extreme case, failure of major components.

Trends in Boilers

The size or rating of boilers is in terms of thousands of pounds of steam supplied per hour. The increase in boiler capacity was rather slow until 1955, as indicated by figure 5.14 which shows maximum boiler capacities for 1905 to 1968, with projections to 1990. Prior to 1950, individual boilers were kept small, in large part because boiler outages were rather numerous, so that it was common design practice to provide multiple boilers and steam header systems to supply a turbine-generator. Advances in metal technology since 1950, with associated lower costs of larger units, have made it economical and reliable to have one boiler per turbine-generator.

It is anticipated that the steam output per boiler will continue to increase. Very large boilers, for turbine-generator units of about 1,200 megawatts output and larger, in some cases will be of the double or twin furnace design. Further design and development is indicated on single furnace enclosures, length of soot blowers (gas-side cleaning equipment), forced and induced draft fans, control systems, and pressurized furnaces before a single boiler is used with a turbine-generator larger than 1,300 megawatts.

With the increase in the steamflow from boilers and the raising of steam conditions to the

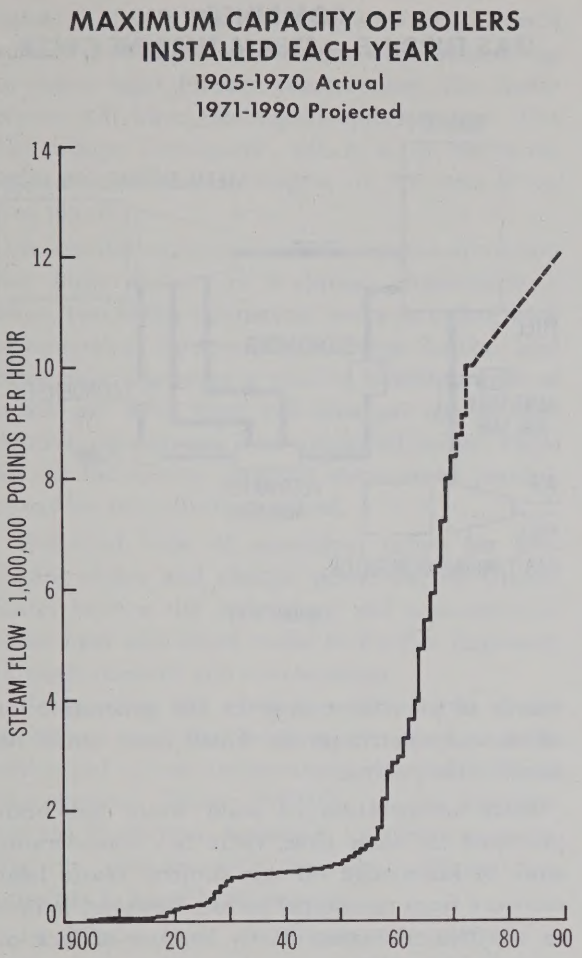


Figure 5.14

3,500 psi and the 1,000°/1,050°F. level, maintenance problems increased and special efforts were needed to maintain service availability and reliability. With high temperatures and high velocity of fuel-air mixtures in the larger boilers, there is an increase in gas-side corrosion and erosion. Sulfur oxides present in the products of combustion produce additional problems of corrosion, and the damaging effects of the corrosive agents are compounded by the abrasive action of fly ash particles. Large single-furnace units experience expansion problems which have resulted in extensive stress cracking of waterwall tubing at buckstays, bustle and windbox attachments, and burner attachments.

Efforts to attain superheat and reheat outlet temperatures significantly in excess of 1,000°F. have met with a difficulty labeled "metal wastage." In coal-fired boilers, this metal wastage form of corrosion is due to a liquid-phase alkali salt which forms at gas temperatures about 1,600°F., and collects on the surface of the boiler tubes under an insulating layer of ash. The metal temperature range in which these salts cause the most corrosion is from 1,100°F. to 1,300°F.

In the newer boilers using once-through flow and supercritical pressures, it is essential that non-corrosive feedwater be used to reduce scale formation and tube failure. In the older boilers, the drum provided a good place to "blowdown" the dissolved solids in the boiler water when the concentrations became too high, but there is no equivalent place in the new once-through systems to perform this function.

Additional design and development work is needed for further increases in size of the boiler, turbine-generator, and principal auxiliaries. Large capacity boilers of today contain over 300 miles of tubing and about 50,000 welds and, because of the pressures and temperatures to which they are subjected, great care must be taken to provide high quality materials and workmanship. Major improvements in metals and metal handling techniques will be required before substantial increases in pressures and temperatures become commonplace.

There are a few installations where two approximately half-size boilers per turbine are being provided in an effort to avoid the very large single boilers which otherwise would be required.

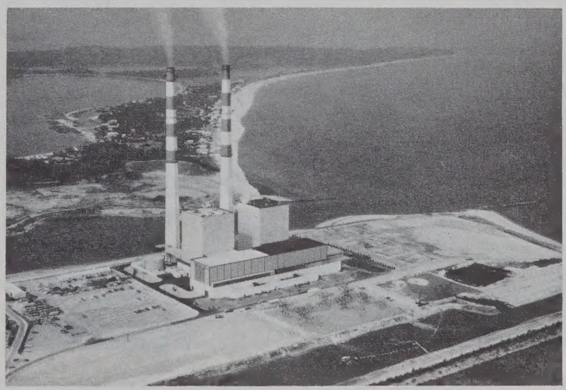


Figure 5.15—Long Island Lighting Company's Northport oil-fired plant has a total generating capacity of 774.2 megawatts in two units.

Prospects for Combined Cycles

In the interest of obtaining electric power and energy at lowest cost, some attention has been given to combined cycles, and they are expected to receive more research and development in the future. An example of a combined cycle is the gas turbine-steam turbine application described below.

Gas Turbine-Steam Turbine

The gas turbine-steam turbine cycle has been proved practical by the 243-megawatt Horseshoe Lake plant installed in 1963 by Oklahoma Gas and Electric Company, by the subsequent 133-megawatt San Angelo installation by West Texas Utilities Company, and by a few other smaller units. The functioning of this cycle is shown on figure 5.17, which is a simplified block diagram of the Horseshoe Lake generating unit. Figure 8.8 shows the San Angelo installation.

Few units of this type are being scheduled for service, probably because of the lack of assurance of a future supply of natural gas or the high cost of other fuels suitable for use in the gas turbine. This type of combined cycle is not likely to be used in large units unless an acceptable coal-burning gas turbine is developed, and prospects for that are not promising.

Combined Steam or Power/Incineration Plants

The electric power industry can play an occasional role in providing a community service through the utilization of municipal waste as a

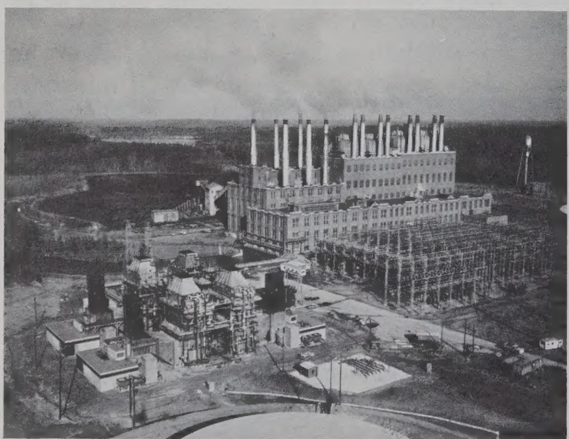


Figure 5.16—Duke Power Company plans to utilize waste heat from gas turbines, shown at left, to permit retirement of several coal-fired boilers in its Riverbend Plant near Charlotte.

COMBINED GAS TURBINE — STEAM TURBINE CYCLE

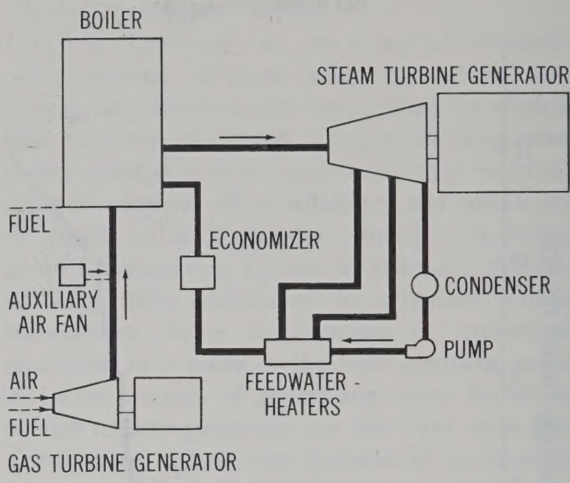


Figure 5.17

source of primary energy in the generation of steam and electric power. Fossil fuels would be saved in the process.

Since incineration of solid waste has been practiced for some time, there is a considerable store of knowledge on this subject. Waste heat recovery from municipal refuse, however, is rare in the United States. Partly because of lack of space for landfill operations, higher fuel costs, and generally lower wages in most European countries, the economics of recovering heat from the burning of wastes are much more favorable and the practice more advanced there than here. Rapid growth in per capita production of refuse in the United States, coupled with such other factors as the growing scarcity and rising costs of suitable landfill areas near urban centers, increasingly stricter environmental control regulations prohibiting open burning and dumping, and the rising costs of fossil fuels, are all making the recovery of waste heat from refuse incineration more economically attractive.

The cities of Chicago, Illinois and Harrisburg, Pennsylvania have started construction of steam-generating incinerators. The Chicago incinerator, consisting of four units, each with a capacity of 400 tons of refuse per day, will have four boilers. Each boiler is expected to generate a steady 110,000 lb/hr of steam at 275 psig and 414°F., using refuse with an average heating

value of 5,000 Btu/lb. The furnace sidewalls consist of vertical water tubes with welded fins to assure tight furnace construction. The incinerator will have electrostatic precipitators. The Harrisburg incinerator, which is of the same type, is scheduled to dispose of 720 tons of refuse per day.

A smaller municipal waste-conversion station was built earlier in Braintree, Massachusetts. Here, two boiler-incinerator units complete with water-cooled furnaces, convection banks, and economizers produce a total of 60,000 pounds of steam per hour from 240 tons per day of residential, commercial, and industrial refuse. Plans for the incinerator included electrostatic precipitators for air pollution control.

Potential users of municipal refuse for producing steam and electric power in the United States believe the technology and economics of waste heat utilization could be further improved through research and development.

Recognizing the need to resolve some of the problems associated with steam generation in municipal refuse incinerators, the Solid Waste Management Office (SWMO) of the Environmental Protection Agency is currently sponsoring two projects with somewhat different approaches to waste heat recovery.

In Menlo Park, California the SWMO is testing on a $1/10$ scale the feeding, shredding, combustion, and gas cleaning components of the Combustion Power Unit-400 (or CPU-400). In full scale, the CPU-400 is a gas turbine incinerator designed to burn refuse and generate electric power; it consumes 400 tons of refuse per day and generates 15,000 kilowatts of electric power. In the CPU-400 the refuse is shredded, dried, and burned in a high-pressure fluid bed reactor operating at 1,650°F. The particulate matter is removed from the high-pressure hot gas and the clean hot gas is expanded through a turbine to drive a compressor and electric generator. Heat energy remaining in the gas downstream from the turbine may be used to generate steam or for other uses. The CPU-400 is capable of furnishing ten percent of the electric power requirements of the community supplying the refuse.

In a St. Louis, Missouri experiment, which is to begin on a full scale at Union Electric Company's Meramec Unit No. 1 (125 MW) early in 1972, 10 to 20 percent of the coal will be replaced with prepared municipal refuse. It is assumed that a relatively small percentage of properly prepared refuse mixed with the regular boiler fuel would present few, if any, problems in the operation of the boilers.

If either or both of these experiments prove to be less troublesome and more economical than the European efforts, they may be adopted in many areas of the country resulting in less costly ways to dispose of city refuse, reducing air pollution, and conserving natural resources. In time, 5 to 10 percent of the Nation's electric power requirements could be produced from municipal refuse.

Automation of Steam-Electric Plants

Large, modern high-pressure, high-temperature generating units have many components requiring continuous monitoring and control, and although many problems must be solved before full automation of these plants will be achieved, there has been progress in automation since the first elementary control systems were developed in the early part of the century. Major steps in the evolution have been the advent of the central control room, the introduction of scanning, alarming, and logging instruments and recorders, and the installation of data-gathering systems. Centralization, a major step in automation, consists of bringing the controls of two or more steam-electric generating units into one central control room, in contrast to the remote monitoring and separate control stations used for manual supervision of the boilers, turbines, and auxiliaries during the first three or four decades of this century.

Plants in operation today vary from those under complete manual supervision to a few that are completely automated. Full automation includes scanning, alarming, logging, and recording, plus computer control of plant starts, running periods, and stops, either scheduled or emergency. All modern plants are automated to some degree but full automation is only rarely employed.

The gas-fired Little Gypsy plant of Louisiana Power & Light Company, a 1961 installation, is an early example of the application of fully automated controls to fossil-fueled generating equipment. Significantly more difficult problems

are involved in complete automation of coal-fired units and some of them still have not been adequately solved.

Economies gained from computer control vary with plant designs, number of units per plant, and operating practices. The degree of automation that will yield maximum economies is that which optimizes: (1) Reduction in overall maintenance costs; (2) detection of equipment problems; (3) reduction of manpower requirements for operation; (4) reduction in plant outage time; (5) fuel economy; and (6) plant reliability, taking into consideration the cost of the automation system.

Successful operation of highly automated power plants requires competent and trained personnel for instrument and computer maintenance. Reductions in total operating personnel are offset partially by increases in higher paid maintenance personnel.

A potential benefit of complete automation could be a reduction in plant investment, because it would lead to better knowledge of equipment requirements and elimination of "over designed" portions of future generating units. Reduction of design margins might reduce equipment costs by more than the cost of an automation system.

CHAPTER 6

NUCLEAR POWER

Introduction

The advent and large scale use of nuclear energy is probably the most important single change in the electric power industry during the past fifty years. The principal theme of nuclear power during its brief history to date has been development and commercialization, but the decades ahead will realize the benefits of effective large scale use of this new source of electric power.

The 1964 National Power Survey (NPS) recognized the important role that nuclear energy would play in the future of the electric industry. There were in 1964 approximately 1,000 megawatts of nuclear generating capacity in commercial operation and 3,000 megawatts under construction or on order. The survey projected 70,000 megawatts of installed nuclear capacity by 1980, a projection that was much higher than other projections of that time. But rather than being too high, the 1964 projections were far too low. Today's NPS projection of 1980 nuclear capacity is 140,000 megawatts, and in independent and more recent estimates, the Atomic Energy Commission predicts 147,000 megawatts. NPS and AEC estimates for 1990 are 475,000 and 500,000 megawatts respectively. Although nuclear plant price quotations doubled over the past five years, nuclear fuel costs have not increased significantly, and nuclear power has remained competitive because of the increases in both capital and operating costs at fossil-fueled plants.

As detailed in chapter 18, the Federal Power Commission now estimates that nuclear capacity will constitute 21 percent of the total electric utility generating capacity in 1980, and 38 percent in 1990. Nuclear plants will produce even larger proportions of the total electric energy to be generated.

The doubling of the projected 1980 nuclear capacity in the present NPS, as compared to the 1964 NPS, reflects the factors behind the surge of nuclear orders in 1967 and 1968 when nuclear units represented more than 50 percent of the total capacity ordered. Greatly increased costs and ordering lead times led to a decline in orders in 1969 and 1970. However, it now appears that the environmental problems of oil and coal-fired plants and the upward cost trend of fossil fuels will not be reversed and thus, with good operating experience on the new large nuclear plants, that orders for nuclear units will continue to increase in what appears to be a stable long term trend.

The increasing commitment to nuclear energy will have important effects on system operation, cost sensitivities, patterns of fuel supply, solutions to environmental problems, capital requirements, personnel training, plant siting, regulation, research, and other factors. While the specific character of these effects is not clearly foreseeable, their understanding by a wide variety of individuals is essential to orderly growth of power systems. Consequently, this chapter provides a brief description of the current status and trends of nuclear power generation.

Accelerated Growth of Nuclear Power Generation

The capacity of nuclear generating units existing, under construction, and on order as of June 30, 1971, as shown in table 6.1 totals 98,520 megawatts. The general geographic location of these plants is shown on figure 6.1. Projected installations to 1990 of nuclear, hydroelectric, and fossil-fueled capacity are shown in figure 6.2. A typical nuclear plant (No. 69 in table 6.1) is shown in figure 6.3.

The megawatts of nuclear generating capacity placed in service and ordered by years, and the amounts which will have to be ordered and

TABLE 6.1

Nuclear Electric Generating Units, Existing and Scheduled,[1] June 30, 1971

Number [2] and Site	Plant Name	Utility	Initial Commercial Capacity (Megawatts)	Initial Commercial Operation
ALABAMA				
1 Decatur	Browns Ferry, Unit 1	TVA	1,065.0	1972
2 Decatur	Browns Ferry, Unit 2	TVA	1,065.0	1973
3 Decatur	Browns Ferry, Unit 3	TVA	1,065.0	1974
4 Dothan	Joseph M. Farley, Unit 1	Ala. Power Co	829.0	1975
5 Dothan	Joseph M. Farley, Unit 2	Ala. Power Co	829.0	1977
ARKANSAS				
6 London	Ark. Nuclear One, Unit 1	Ark. Power & Light Co	820.0	1973
7 London	Ark. Nuclear One, Unit 2	Ark. Power & Light Co	920.0	1975
CALIFORNIA				
8 Humboldt Bay	Humboldt Bay	Pacific Gas & Elec. Co	68.5	1963
9 San Clemente	San Onofre, Unit 1	So. Calif. Edison & San Diego Gas & Elec.	430.0	1968
10 San Clemente	San Onofre, Unit 2	So. Calif. Edison & San Diego Gas & Elec.	1,140.0	1976
11 San Clemente	San Onofre, Unit 3	So. Calif. Edison & San Diego Gas & Elec.	1,140.0	1977
13 Diablo Canyon	Diablo Canyon, Unit 1	Pacific Gas & Elec. Co	1,060.0	1974
14 Diablo Canyon	Diablo Canyon, Unit 2	Pacific Gas & Elec. Co	1,060.0	1975
15 Clay Station	Rancho Seco	Sacramento Mun. Util. Dist	804.0	1973
16 Mendocino County	Mendocino, Unit 1	Pacific Gas & Elec. Co	1,128.0	1976
43 Mendocino County	Mendocino, Unit 2	Pacific Gas & Elec. Co	1,128.0	1978
COLORADO				
17 Platteville	Ft. St. Vrain	Public Serv. Co. of Colo	330.0	1972
CONNECTICUT				
18 Haddam Neck	Haddam Neck	Conn. Yankee Atomic Power Co	575.0	1968
19 Waterford	Millstone, Unit 1	Northeast Utilities	652.1	1971
20 Waterford	Millstone, Unit 2	Northeast Utilities	828.0	1974
FLORIDA				
21 Turkey Point	Turkey Point, Unit 3	Fla. Pwr. & Light Co	693.0	1971
22 Turkey Point	Turkey Point, Unit 4	Fla. Pwr. & Light Co	693.0	1972
23 Red Level	Crystal River, Unit 3	Florida Power Corp	858.0	1972
24 Ft. Pierce	Hutchinson Is., Unit 1	Fla. Pwr. & Light Co	800.0	1974
118 Ft. Pierce	Hutchinson Is., Unit 2	Fla. Pwr. & Light Co	800.0	1976
GEORGIA				
25 Baxley	Edwin I. Hatch, Unit 1	Georgia Power Co	786.0	1973
26 Baxley	Edwin I. Hatch, Unit 2	Georgia Power Co	786.0	1976
ILLINOIS				
27 Morris	Dresden, Unit 1	Commonwealth Edison Co	200.0	1960
28 Morris	Dresden, Unit 2	Commonwealth Edison Co	809.0	1970
29 Morris	Dresden, Unit 3	Commonwealth Edison Co	809.0	1971
30 Zion	Zion, Unit 1	Commonwealth Edison Co	1,050.0	1972
31 Zion	Zion, Unit 2	Commonwealth Edison Co	1,050.0	1973
32 Cordova	Quad-Cities, Unit 1	Comm. Ed. Co.—Iowa-Ill. Gas & Electric Co.	809.0	1971
33 Cordova	Quad-Cities, Unit 2	Comm. Ed. Co.—Iowa-Ill. Gas & Electric Co.	809.0	1972
34 Seneca	La Salle County, Unit 1	Commonwealth Edison Co	1,078.0	1975

TABLE 6.1—Continued

Number [2] and Site	Plant Name	Utility	Initial Commercial Capacity (Megawatts)	Initial Commercial Operation
ILLINOIS—Continued				
35 Seneca..........	La Salle County, Unit 2...	Commonwealth Edison Co.........	1,078.0	1976
([3])..		Commonwealth Edison Co.........	1,100.0	1978
([3])..		Commonwealth Edison Co.........	1,100.0	1979
INDIANA				
36 Dune Acres......	Bailly....................	Northern Ind. Public Service Co....	660.0	1976
IOWA				
37 Cedar Rapids....	Duane Arnold...........	Iowa Elec. Lt. & Pwr. Co.........	529.7	1973
LOUISIANA				
12 Taft............	Waterford...............	Louisiana Pwr. & Lt. Co..........	1,165.0	1977
MAINE				
38 Wiscasset........	Maine Yankee...........	Me. Yankee Atomic Pwr. Co.......	790.0	1972
MARYLAND				
39 Lusby...........	Calvert Cliffs, Unit 1......	Balt. Gas & Elec. Co..............	845.0	1973
40 Lusby...........	Calvert Cliffs, Unit 2......	Balt. Gas & Elec. Co..............	845.0	1974
MASSACHUSETTS				
41 Rowe...........	Yankee..................	Yankee Atomic Elec. Co...........	175.0	1961
42 Plymouth........	Pilgrim..................	Boston Edison Co.................	655.0	1971
MICHIGAN				
44 Big Rock Point...	Big Rock Point..........	Consumers Power Co..............	70.3	1965
45 South Haven.....	Palisades................	Consumers Power Co..............	700.0	1971
46 Lagoona Beach...	Enrico Fermi, Unit 1......	Detroit Edison Co................	60.9	1970
47 Lagoona Beach...	Enrico Fermi, Unit 2......	Detroit Edison Co................	1,123.0	1974
48 Bridgman........	Donald C. Cook, Unit 1...	Ind. & Mich. Elec. Co............	1,054.0	1973
49 Bridgman........	Donald C. Cook, Unit 2...	Ind. & Mich. Elec. Co............	1,060.0	1974
50 Midland.........	Midland, Unit 1..........	Consumers Power Co..............	492.0	1976
51 Midland.........	Midland, Unit 2..........	Consumers Power Co..............	818.0	1977
MINNESOTA				
53 Monticello.......	Monticello..............	Northern States Pwr. Co...........	545.0	1971
54 Red Wing.......	Prairie Island, Unit 1.....	Northern States Pwr. Co...........	530.0	1972
55 Red Wing.......	Prairie Island, Unit 2.....	Northern States Pwr. Co...........	530.0	1974
NEBRASKA				
56 Fort Calhoun....	Ft. Calhoun.............	Omaha Public Pwr. Dist...........	457.4	1972
57 Brownville.......	Cooper..................	Nebraska Pub. Pwr. Dist. & Iowa Pwr. & Light Co.	778.0	1973
NEW JERSEY				
59 Toms River......	Oyster Creek............	Jersey Cent. Pwr. & Lt. Co........	560.0	1969
60 Salem...........	Salem, Unit 1............	Pub. Serv. Elec. & Gas Co. of New Jersey	1,050.0	1973
61 Salem...........	Salem, Unit 2............	Pub. Serv. Elec. & Gas Co. of New Jersey	1,050.0	1974
62 Bordentown......	Newbold, Unit 1.........	Pub. Serv. Elec. & Gas Co. of New Jersey	1,088.0	1975
63 Bordentown......	Newbold, Unit 2.........	Pub. Serv. Elec. & Gas Co. of New Jersey	1,088.0	1977
65 Lacey Township..	Forked River............	Jersey Cent. Pwr. & Light Co......	1,140.0	1976
NEW YORK				
66 Indian Point.....	Indian Point, Unit 1......	Consolidated Edison Co...........	265.0	1962
67 Indian Point.....	Indian Point, Unit 2......	Consolidated Edison Co...........	873.0	1971
68 Indian Point.....	Indian Point, Unit 3......	Consolidated Edison Co...........	965.0	1973

TABLE 6.1—Continued

Number [2] and Site	Plant Name	Utility	Initial Commercial Capacity (Megawatts)	Initial Commercial Operation
NEW YORK—Continued				
69 Scriba	Nine Mile Point	Niag. Mohawk Pwr. Corp	625.0	1969
70 Rochester	R. E. Ginna	Roch. Gas & Elec. Co	420.0	1970
71 Brookhaven	Shoreham	Long Island Lighting Co	819.0	1975
72 Lansing	Bell	N. Y. State Elec. & Gas Co	838.0	1978
73 Verplanck	Verplanck	Con. Edison Co	1,115.0	1978
74 Scriba	James A. Fitzpatrick	Pwr. Auth. of State of New York	821.0	1973
NORTH CAROLINA				
75 Southport	Brunswick, Unit 1	Carolina Pwr. & Lt. Co	821.0	1975
76 Southport	Brunswick, Unit 2	Carolina Pwr. & Lt. Co	821.0	1974
78 Cowans Ford	Wm. B. McGuire, Unit 1	Duke Power Co	1,150.0	1975
79 Cowans Ford	Wm. B. McGuire, Unit 2	Duke Power Co	1,150.0	1977
52 Bonsal	Shearon Harris, Unit 1	Carolina Pwr. & Lt. Co	900.0	1977
58 Bonsal	Shearon Harris, Unit 2	Carolina Pwr. & Lt. Co	900.0	1978
64 Bonsal	Shearon Harris, Unit 3	Carolina Pwr. & Lt. Co	900.0	1979
77 Bonsal	Shearon Harris, Unit 4	Carolina Pwr. & Lt. Co	900.0	1980
OHIO				
80 Oak Harbor	Davis-Besse	Toledo Edison-Clev. Elec. Illum. Co.	872.0	1974
82 Moscow	Wm. H. Zimmer	Cincinnati Gas & Elec. Co	810.0	1975
OREGON				
84 Prescott	Trojan	Portland Gen. Elec. Co	1,130.0	1974
PENNSYLVANIA				
86 Peach Bottom	Peach Bottom, Unit 1	Philadelphia Elec. Co	40.0	1967
87 Peach Bottom	Peach Bottom, Unit 2	Philadelphia Elec. Co	1,065.0	1973
88 Peach Bottom	Peach Bottom, Unit 3	Philadelphia Elec. Co	1,065.0	1974
89 Pottstown	Limerick, Unit 1	Philadelphia Elec. Co	1,065.0	1975
90 Pottstown	Limerick, Unit 2	Philadelphia Elec. Co	1,065.0	1977
91 Shippingport	Shippingport	Duquesne Light Co	90.0	1957
92 Shippingport	Beaver Valley	Duquesne Light Co., Ohio Edison Co., and Pennsylvania Pwr. Co.	847.0	1973
93 Middletown	Three Mile Island, Unit 1	Metropolitan Edison Co	831.0	1972
94 Middletown	Three Mile Island, Unit 2	Jersey Cent. Pwr. & Lt. Co	907.0	1974
95 Berwick	Susquehanna, Unit 1	Pa. Power & Light Co	1,052.0	1977
96 Berwick	Susquehanna, Unit 2	Pa. Power & Light Co	1,052.0	1980
SOUTH CAROLINA				
97 Hartsville	H. B. Robinson	Carolina Pwr. & Lt. Co	700.0	1971
98 Seneca	Oconee, Unit 1	Duke Power Co	841.0	1971
99 Seneca	Oconee, Unit 2	Duke Power Co	886.0	1972
100 Seneca	Oconee, Unit 3	Duke Power Co	886.0	1973
101 Parr	Virgil C. Summer	S. Carolina Elec. & Gas Co	900.0	1977
TENNESSEE				
102 Daisy	Sequoyah, Unit 1	TVA	1,124.0	1974
103 Daisy	Sequoyah, Unit 2	TVA	1,124.0	1974
110 Spring City	Watts Bar, Unit 1	TVA	1,169.0	1976
111 Spring City	Watts Bar, Unit 2	TVA	1,169.0	1977
VERMONT				
104 Vernon	Vermont Yankee	Vt. Yankee Nuclear Pwr. Corp	513.9	1971
VIRGINIA				
105 Gravel Neck	Surry, Unit 1	Va. Elec. & Power Co	780.0	1971
106 Gravel Neck	Surry, Unit 2	Va. Elec. & Power Co	780.0	1972
107 Mineral	North Anna, Unit 1	Va. Elec. & Power Co	845.0	1974

TABLE 6.1—Continued

Number [2] and Site	Plant Name	Utility	Initial Commercial Capacity (Megawatts)	Initial Commercial Operation
VIRGINIA—Continued				
108 Mineral	North Anna, Unit 2	Va. Elec. & Power Co	845.0	1975
81 Mineral	North Anna, Unit 3	Va. Elec. & Power Co	900.0	1977
83 Mineral	North Anna, Unit 4	Va. Elec. & Power Co	900.0	1978
WASHINGTON				
109 Richland	N-Reactor/WPPSS Steam	Wash. Pub. Pwr. Supply System	790.0	1966
117 Richland	Hanford No. 2	Wash. Pub. Pwr. Supply System	1,103.0	1977
WISCONSIN				
112 Genoa	LaCrosse	Dairyland Pwr. Coop	50.0	1971
113 Two Creeks	Point Beach, Unit 1	Wisc. Mich. Pwr. Co	497.0	1970
114 Two Creeks	Point Beach, Unit 2	Wisc. Mich. Pwr. Co	497.0	1971
115 Carlton	Kewaunee	Wisc. Public Serv. Corp	540.0	1972
UNKNOWN				
([3])		TVA	1,201.0	1977
([3])		TVA	1,201.0	1978
Total			98,519.8	

[1] Includes units in operation, under construction, and on order as reported in AEC public announcement giving status of units as of June 30, 1971. Since then, some of the earlier scheduled dates for initial operation show additional delays.

[2] Numbers correspond to those on figure 6.1.

[3] Site not selected, and not shown on figure 6.1.

placed in service to meet the projected schedule of nuclear power installations through 1990, are shown graphically on figure 6.4. The heavy ordering in 1967 reflected, among other things, the rush by utilities to obtain a priority position in an overloaded manufacturing industry. Recent increases in costs of fossil fuels and ever-increasing restrictions on the quality of fuels which may be used for electric power generation are expected to accelerate the swing toward the scheduling of more nuclear power plants. Figure 6.4 was prepared on the basis of a six-year period between nuclear commitment and the in-service date. Currently, most systems consider seven years a more reasonable allowance because of the many environmental, regulatory, construction, and labor problems which may be encountered. A recent court decision (see next section) with respect to added environmental analyses as a part of licensing reviews, could further extend nuclear plant lead times, at least in the short term. Nevertheless, while it is believed that, on the average, six years should be adequate, current reviews and delays are drastically affecting prospective schedules.

Regulation

Nuclear plants are subject to Federal, State, and local regulation, with State and local regulation primarily concerned with zoning, waste disposal, and thermal effects, and Federal regulation concerned with matters related to the National Environmental Policy Act of 1969 and with nuclear safety under the Atomic Energy Act. Construction and operation of nuclear plants in the United States are regulated by the AEC through licensing. The safety record of the nuclear power industry is excellent to date and this is certainly due in part to the strict licensing requirements.

Plant Licensing

Construction Permit

A utility proposing to build a plant is required to file with the AEC an application for a construction permit and include a preliminary design of the nuclear facility, a Preliminary Safety Analysis Report (PSAR), and an environmental impact statement. These assess the proposed site with respect to population centers,

NUCLEAR ELECTRIC GENERATING UNITS

Existing and Scheduled

June 30, 1971

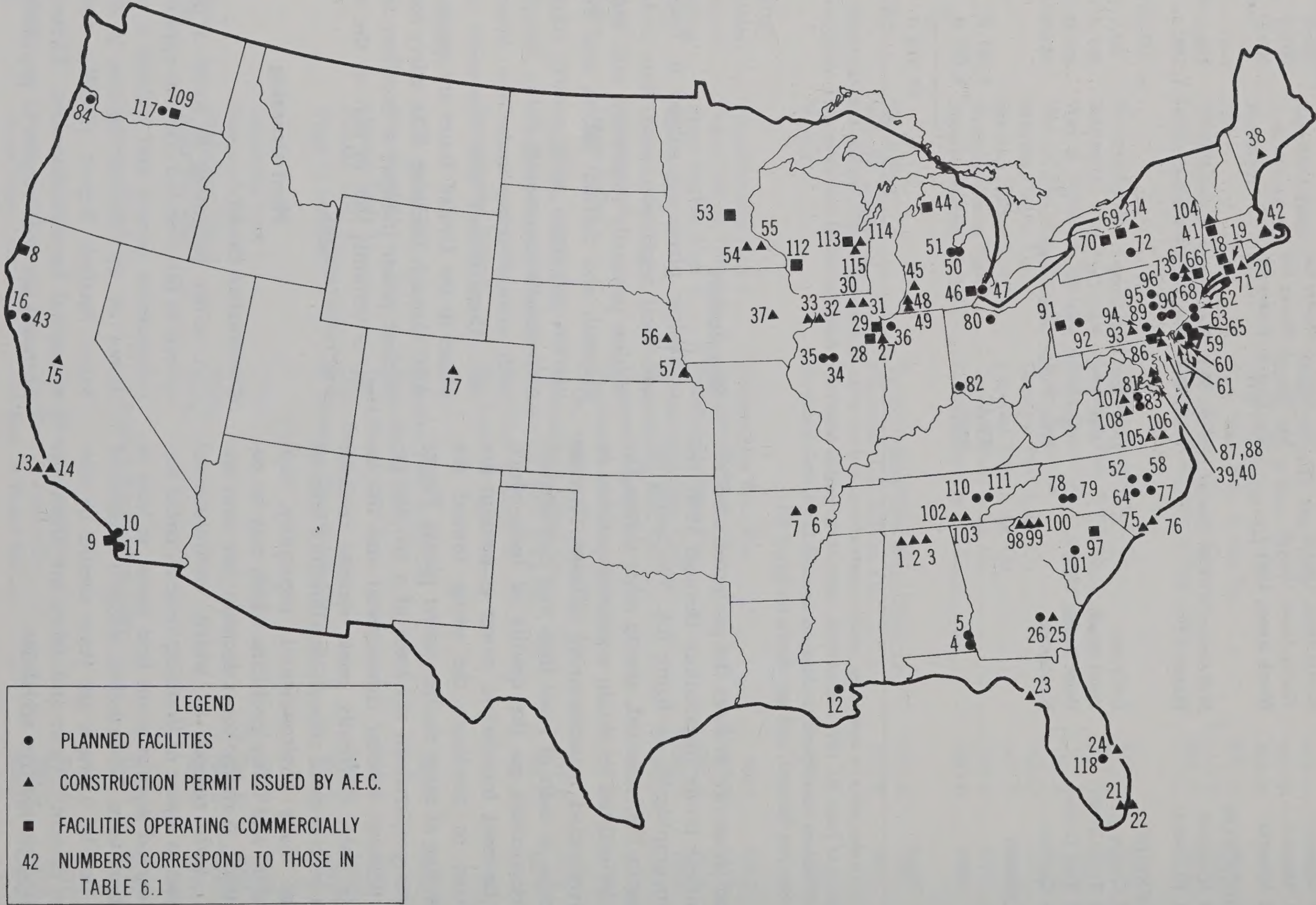


Figure 6.1

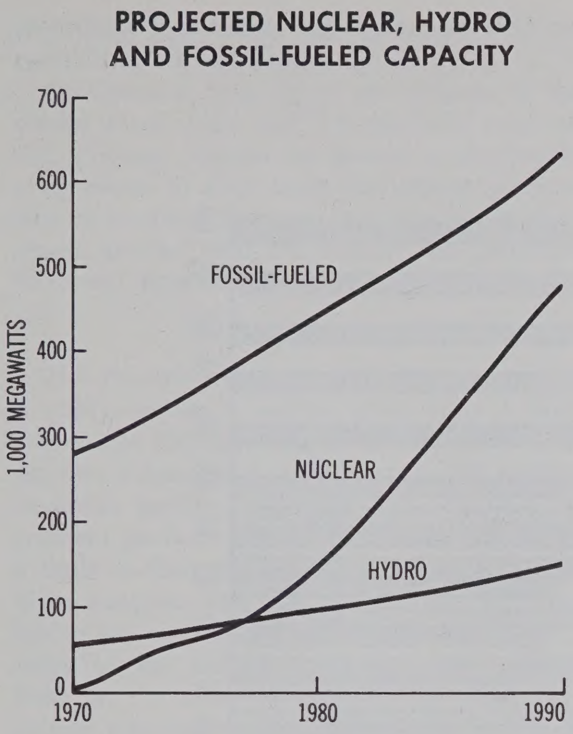


Figure 6.2

topography, meteorology, hydrology, seismology, and geology, and overall effect on the ecology. This information is reviewed by the AEC staff, the Advisory Committee on Reactor Safeguards (ACRS), and other regulatory agencies. If found satisfactory, a public hearing by an Atomic Safety and Licensing Board is held. A construction permit may then be issued. The time required for this procedure is now about 20 months. Permanent plant construction may not begin without this permit, unless a waiver is granted for specific work.

Operating License

The Final Safety Analysis Report is submitted to the AEC while construction of the nuclear facility is under way, but after the major design details are available and the associated research and development is completed. Following further review by the AEC staff and ACRS, including presentation of evidence that the plant has been designed and constructed as described, and after a public hearing is held if requested, an operating license is issued.

The AEC has proposed an amendment to the Atomic Energy Act to remove the mandatory requirement for a complete review at the operating permit stage, in an attempt to simplify the licensing process. However, in September 1971, the AEC expanded its licensing procedures to include consideration of all environmental factors, non-nuclear as well as nuclear, in compliance with the provisions of the National Environmental Policy Act of 1969, as interpreted by the United States Court of Appeals in the Calvert Cliffs case.

The licensing requirements for nuclear facilities are detailed, lengthy, and stringent. With plant standardization, more experienced personnel, additional codes and standards, and fewer design changes during construction, it may be possible to expedite the licensing procedure without compromising public health and safety. Growing environmental concern, however, militates against any reduction in the time required for obtaining all the necessary Federal, State, and local licenses and permits for the construction of a major nuclear facility.

Operator Licensing

The AEC requires the licensing of personnel who operate a licensed nuclear facility. Two grades of licenses are issued, Operator and Senior Operator. Both require detailed written and oral examinations on many aspects of nuclear plant operations. For a Senior Operator's license, a more thorough knowledge of the basic nuclear processes, reports, and administrative

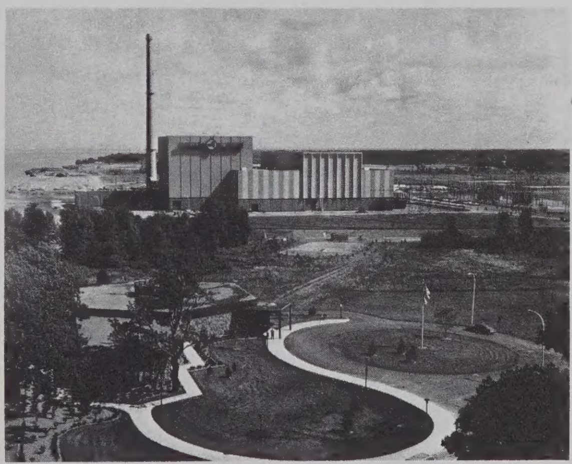


Figure 6.3—Niagara Mohawk Power Corporation's Nine Mile Point plant on Lake Ontario in New York. The visitors' center and recreational area are shown in the foreground.

NUCLEAR ELECTRIC CAPACITY

Existing And Projected

December 31, 1970

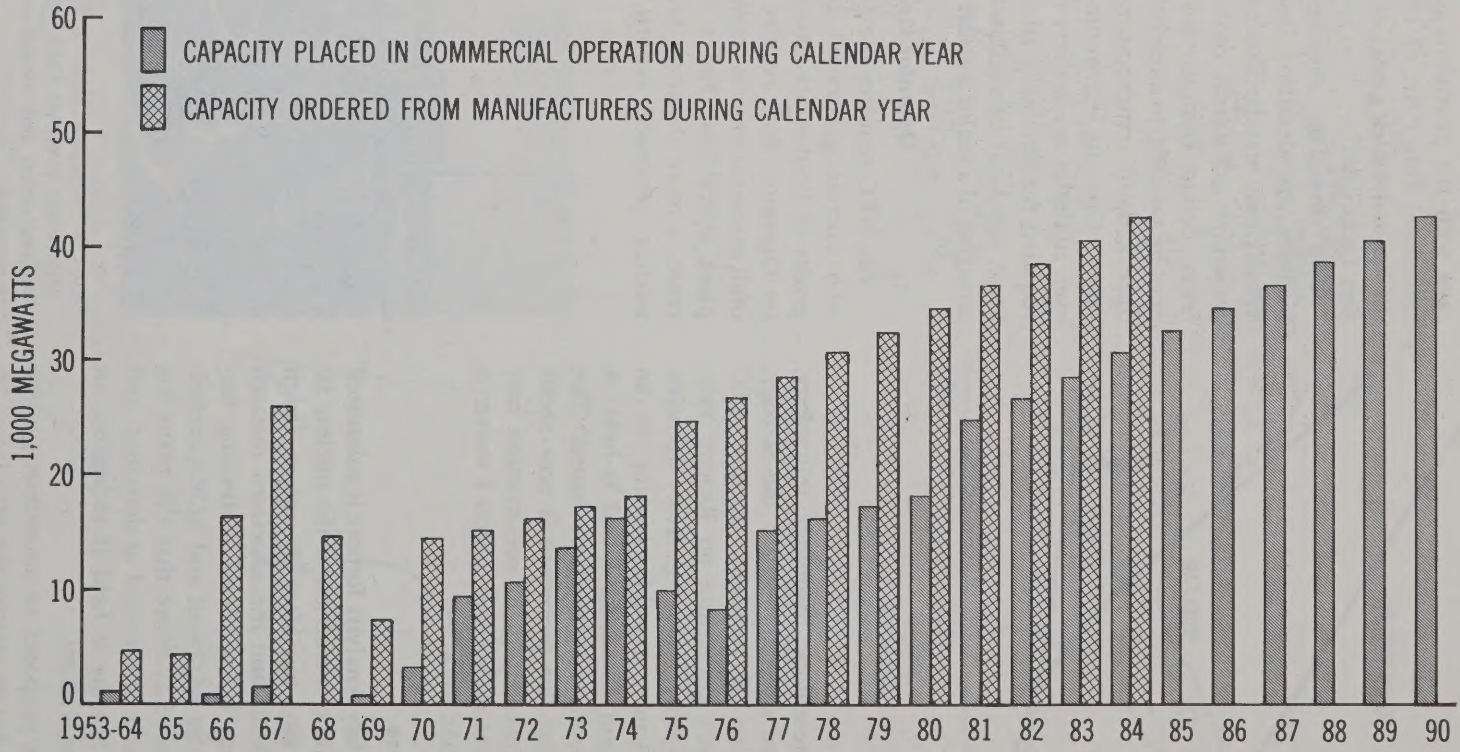


Figure 6.4

procedures is required. Satisfactory physical examinations are mandatory.

An Operator must be at the controls of the reactor at all times, and it is generally required that a Senior Operator be present at the facility at all times. By 1975, some 600 persons per year will be receiving operator or senior operator licenses, and by 1990, the number will probably be several thousand per year.

Nuclear Insurance

The Price-Anderson Act of 1957 requires that a utility owning a nuclear plant carry a fixed amount of liability insurance. The private insurance industry will provide up to $82 million in public liability insurance. The Federal Government provides the additional coverage up to a limit of $560 million. Both conventional liability insurance and property insurance for damage to the nuclear plant itself must also be provided by the utility. There is a $100 million limit on the latter coverage by the worldwide private insurance market. With a continuing favorable loss record, this limit might be increased and be available at lower cost.

Types of Reactor Systems in Service and Being Built

With one exception, the power reactors now in operation and being built are of the "thermal" classification in contrast to "fast" reactor concepts. Thermal reactors employ moderating materials to slow the neutrons before the majority of fissions occur, whereas in fast reactors most fissions are produced by neutrons with much higher speeds or energy levels. The latter approach, while technically more difficult, will utlimately provide the capability of utilizing a much greater portion of the potential energy in the uranium and thorium ores. Light water reactors of the pressurized water and boiling water types are the principal thermal reactors now being constructed and planned in this country. These types are described briefly in the following sections.

Pressurized Water Reactor

The first full-scale application of nuclear power exclusively for steam-electric generation in the United States was the pressurized water reactor (PWR) at Shippingport, Pennsylvania, a 90-megawatt installation placed in service in 1957. Subsequent pressurized water reactors have the same basic plant cycle but significant improvements in design have been made.

In the PWR system, water at some 2,000 psi serves as both moderator and coolant as it passes through the reactor core where heat from the fuel elements is absorbed. The heated water then passes to a separate heat exchanger (steam generator) where saturated or slightly superheated steam is produced on the secondary side. This steam drives the turbine and connected generating unit. Radioactivity is confined to the primary side of the steam generator so that the turbine steam system is not radioactive. Net plant thermal efficiencies are on the order of 33 percent.

Fuel in present-day PWR systems is in the form of slightly enriched uranium dioxide pellets containing some 3 percent of the U-235 isotope of uranium. The fuel is fabricated in bundles of tubes of zirconium alloy some 12 feet long. Control rods replace some of the fuel rods in selected bundles, and further control is achieved through the use of boric acid added to the primary water.

Boiling Water Reactor

The second full-scale application of nuclear power for steam-electric generation in this country was the boiling water reactor (BWR) at Dresden, Illinois, a 200-megawatt unit (designed for 180 MW) placed in commercial service in 1960. As each subsequent BWR has been constructed, refinements and improvements have been made.

In the BWR's, steam is generated directly in the reactor core as water is circulated through it at a pressure of approximately 1,000 psi. After passing through mechanical steam separators and dryers within the reactor vessel, the saturated steam is piped directly to the turbogenerator. With this direct steam cycle arrangement, some radioactivity will be present in the steam. This requires some shielding of the turbine and other heat cycle components.

Fuel rods are similar to those of the PWR although they are larger in diameter and fewer rods are required for each bundle. They have an enrichment of about 2.5 percent uranium 235. Cruciform control rods containing boron are usually inserted between each group of four fuel bundles. Further control is often achieved

through the use of consumable neutron absorber material inserted into the fuel rods. The water removed in the mechanical steam separators and dryers along with a portion of the reactor coolant inventory is recirculated through the core using a combination of variable speed and jet pumps. The power output of the reactor is regulated by both rod movement and changes in the recirculation flow rate through the core.

Long-term fuel performance of the two types of light water reactors is comparable.

Nuclear Fuels

At present, ownership of nuclear fuel material is in transition from the Government to the private sector. Prior to January 1, 1969, the utilities leased special nuclear material from the Atomic Energy Commission (AEC), paying a charge for its use and for depletion and losses. On January 1, 1969, the AEC initiated toll-enrichment of uranium owned by utilities or fuel suppliers. During the following two years a utility could either lease AEC-owned enriched uranium or supply to the AEC natural uranium it had procured and converted to uranium hexafluoride for enriching of the U-235 isotope. On January 1, 1971, the AEC discontinued new fuel leases. Special nuclear material previously leased can remain under lease until June 30, 1973, by which time it must be converted to private ownership.

The long-term effect that private ownership will have on nuclear fuel costs remains to be shown. The AEC formerly paid higher than worldmarket prices for natural uranium to encourage exploration. Further, the buy-back of plutonium produced in civilian nuclear power plants at a guaranteed price by the AEC was discontinued on December 31, 1970, and its value will depend to a large extent on how well the private market utilizes plutonium to fulfill the needs of advanced reactor types, or for recycle as fuel in PWR and BWR plants.

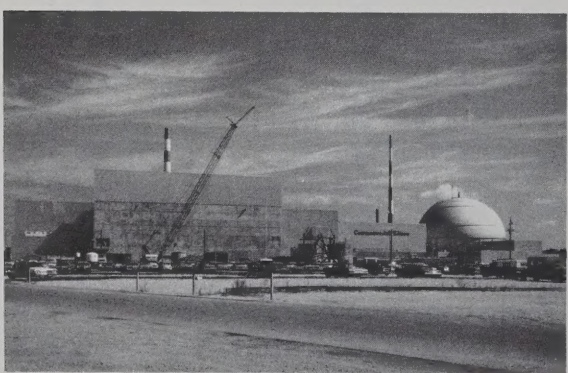


Figure 6.5—Two 809-MW units under construction at Commonwealth Edison Company's Dresden plant.

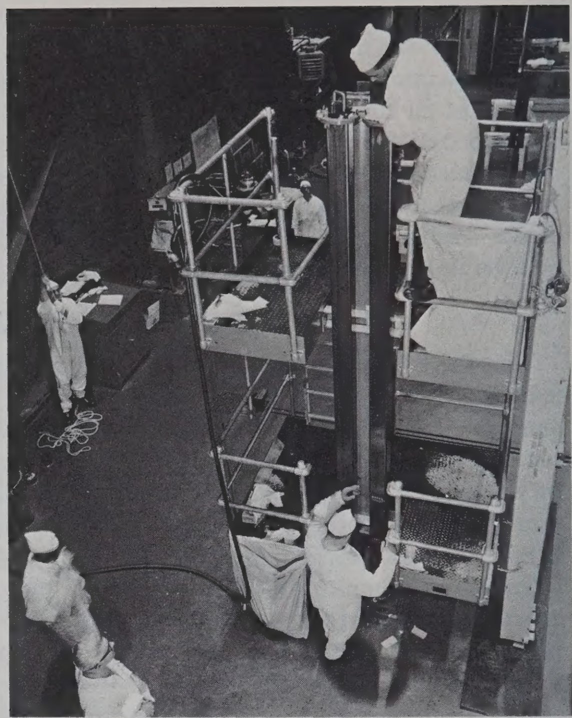


Figure 6.6—Technicians prepare uranium fuel bundles for loading at Niagara Mohawk's Nine Mile Point generating station. The fuel core in the power plant's reactor contains 115 tons of uranium oxide pellets encased in 532 of these vertical bundles. Each bundle contains 49 fuel rods. Heat from the fission process boils more than six million pounds of water per hour into high-pressure steam.

Fuel Requirements and Supply

Although the nuclear power industry is young, there is a long range concern that the limited supply of uranium ore will be expended on thermal reactors which presently convert less than 2 percent of the fuel's latent energy to electricity. Uranium ore is the only material that occurs naturally as fissile material. The amount of U_3O_8 required for diffusion plant feed increases from about 7,500 short tons per year in 1970 to an estimated 40,800 tons in 1980 and 127,000 tons in 1990, assuming no recycle of

plutonium. To lessen this drain on limited uranium reserves, it is planned to use the fissile plutonium-239 or uranium-233 isotopes produced by the irradiation of uranium-238 and thorium-232 as feed material for other power reactors, thereby making for better utilization of uranium and thorium resources. In this regard, the AEC considers the development of a fast breeder reactor, which produces more plutonium-239 fuel than it consumes, to be its highest priority civilian nuclear power project.

Figure 6.7 illustrates how the introduction of fast breeders would cause the overall requirements for uranium to decline as the breeders assume the major role in nuclear power.

Fuel Cycles

In contrast to the relatively simple steps of extraction, processing and combustion of fossil fuel, the complete nuclear fuel cycle involves a long period of time, includes many operations both before and after fuel usage, and requires a high inventory level throughout the fuel cycle. The following paragraphs discuss the types of fuel cycles currently in use and projected for the next two decades. These are the uranium fuel cycle, the thorium fuel cycle, and the plutonium fuel cycle. A diagram of a nuclear fuel cycle is shown in figure 6.8.

Uranium Fuel Cycle

All processes in the uranium cycle, except the enriching process and the conversion of re-

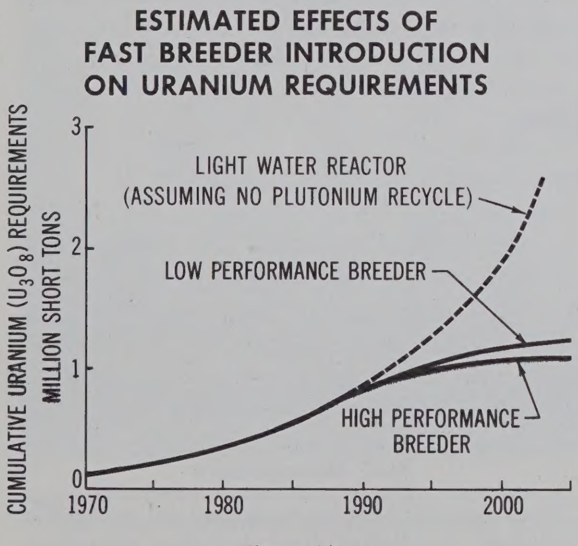


Figure 6.7

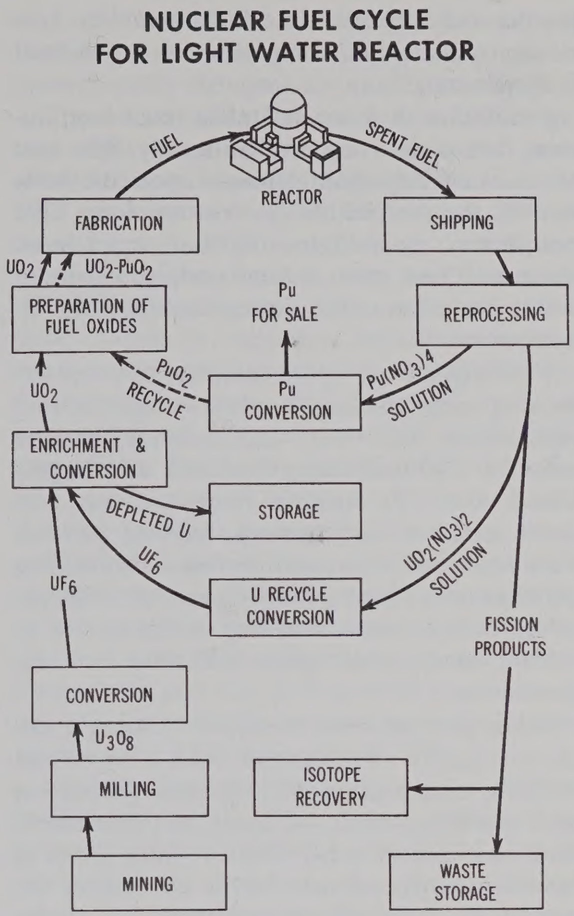


Figure 6.8

covered fuels to nitrate form, are currently available from one or more private suppliers.

Head-End Processes. Although some countries use natural uranium in their power reactor programs, enriched uranium is used in the United States. Enrichment results in fewer constraints on design, more compact cores, longer fuel life, and economic recovery of the plutonium discharge.

Beginning with the uranium ore concentrate (U_3O_8), or yellowcake, the uranium is converted to uranium hexafluoride gas (UF_6). This is then delivered to one of the AEC's three gaseous diffusion plants where the amount of uranium U-235 isotope content is increased or "enriched" from less than one percent to whatever degree of enrichment is desired, usually about two to three percent.

Fuel Fabrication. After the uranium hexafluoride has been enriched to the desired degree, it is converted into uranium dioxide (UO_2)

powder and fabricated into fuel assemblies. Fabrication is a major component of the overall fuel cycle cost.

Irradiation in Reactor. Unlike fossil fuel, nuclear fuel is not consumed uniformly. The rate of uranium depletion depends upon the location of the fuel within the reactor core. This complicates the fuel loading and replacement patterns. These patterns have undergone considerable evolution as the nuclear industry has developed.

The original concept of complete fuel replacement at each refueling shutdown simplified fuel replacement but was uneconomical because some of the fuel being replaced was largely unexpended. To achieve more uniform and more complete fuel burnup, loading patterns were developed incorporating fuel with differing enrichments. These patterns required multiple calculations for each refueling of the reactor to achieve most advantageous relocation and replacement.

Other patterns were developed utilizing a single enrichment feed material and a form of fuel shuffling or rearrangement. In this process, at each refueling shutdown, spent fuel is removed from the central zone, fuel in outer zones is moved inward, and new fuel is inserted in the outer zones. This pattern simplified fuel calculations but introduced a further complication. During the first several years of production, the central zone necessarily had to be removed before it could attain the desired level of fuel depletion. This resulted in high fuel costs for the first several years of operation. More complex zone patterns coupled with varying enrichment levels are presently being designed into new units to minimize these costs. As more experience is gained, core design and operation should continue to improve. Control rod arrangements also affect fuel consumption rates, and computers are being used to assist in selecting control-rod patterns to optimize core performance and economy.

Tail-End Processes. Spent fuel contains 30 to 50 percent of the original fissile uranium as well as fissile plutonium produced in the reactor. Reprocessing concentrates the radioactive waste for disposal and recovers the uranium and plutonium so they can be recycled. Reuse of these fuel materials is essential for fuel cycle economy, representing significant savings unless the comparable costs of disposal and reprocessing should markedly change.

The possible recovery of additional isotopes of such elements as neptunium, cesium, strontium, cerium, americium, promethium, and curium may serve to reduce the reprocessing costs. The volume of the remaining radioactive wastes is reduced by evaporation, and the solution is neutralized and stored in buried tanks in accordance with strict government regulations. A policy providing for conversion of these wastes to an acceptable solid form and shipment to a Federal Repository for permanent custody has been announced by the AEC.

Although the cost of shipping spent fuel is quite high, it is a small part of fuel cycle costs. Spent fuel discharged from reactors is highly radioactive and must be transported to the reprocessing plant in shielded containers. The containers are constructed primarily of lead surrounded by steel casing and are designed to withstand severe impact and fire without allowing spent fuel material to escape.

Thorium Cycle

The thorium cycle is similar to the uranium cycle except that the feed material is a mixture of thorium and uranium with a very high U-235 isotope content. Neutrons produced by fissioning of the uranium in the power reactor convert thorium to fissile uranium-233 which is a better fuel than the original uranium-235. After reprocessing, the fissile uranium is used to enrich replacement fuel. The thorium cycle has been used successfully in light water reactors and is projected for possible use in advanced converter reactors, but it would require establishment of a complete thorium fuel processing and recovery cycle.

Plutonium Cycle

While plutonium is a product of the uranium cycle, the use of plutonium as a principal fuel material awaits development of the fast breeder reactor. Plutonium will be recycled in light water reactors until breeders are available, at which time it is expected to have economic superiority as a breeder reactor fuel.

Fuel Management

Fuel management encompasses all economic, technical, and scheduling decisions related to

nuclear fuel throughout the entire nuclear fuel cycle. During the early application of nuclear reactors to power generation, many utilities did not have the expertise to assume major fuel management responsibility and it was largely delegated to the fuel supplier. Now the situation is changing and some utilities are building nuclear staffs whose major concern is optimization of the fuel cycle. In the future, it is expected that the utilities will assume more of the responsibility for fuel management. Regardless of how the responsibility is divided, close cooperation between the fuel supplier and the utility is required.

Nuclear Plant Costs

Capital Costs

The nuclear electric power industry is based on a new and dynamic technology to which our future power supply is being committed at an unprecedented rate. The amount of nuclear capacity in the future will be determined largely by the competitive position of nuclear power with respect to comparative environmental factors, the cost of fossil-fueled plants, and the availability and costs of fossil fuels that can be burned under stringent air quality standards.

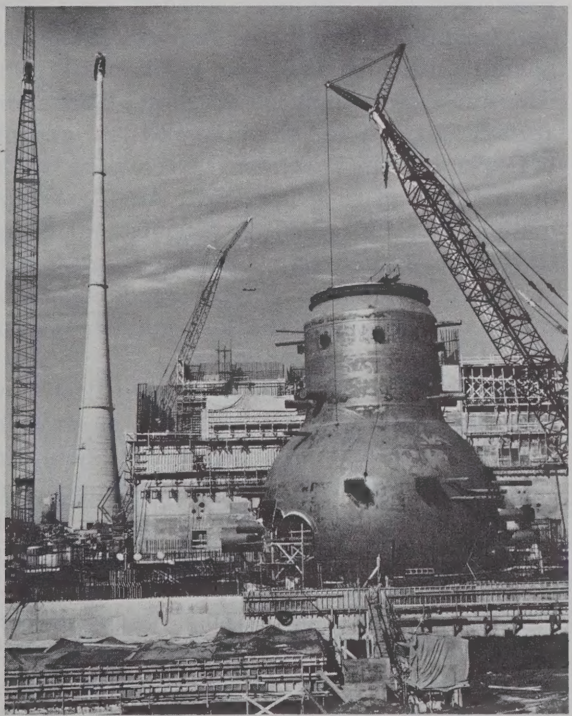


Figure 6.9—TVA's Browns Ferry Nuclear Plant will have three units, each with an electrical generating capacity of 1,152 megawatts.

The estimated capital costs of a 1,000-megawatt light water reactor plant increased from about \$135 per kilowatt in March 1967 to about \$220 per kilowatt by June 1969, and to \$300 or more by early 1971. Lengthening construction schedules, higher interest rates, new and more stringent operating and safety codes and standards, changes in regulatory requirements, cooling water temperature restrictions and other environmental factors, and increased costs of equipment and labor all have had most significant effects. Except for possible effects of inflation, future capital costs per kilowatt should decrease to reflect economies inherent in standardization of components, advances in technology that result in increased reactor power density or decreased fuel fabrication costs, and the economies of scale that will accompany continuing increases in unit size. It is possible that technology will be available to construct units in sizes approaching 3,000 megawatt by 1990.

Nuclear plants have higher capital costs than fossil-fueled plants. The higher capital costs, however, tend to be offset by lower fuel costs. It is important, therefore, to operate nuclear plants at high plant capacity factors to achieve competitive total energy costs.

The long periods now required for licensing and construction of nuclear electric generating capacity present a serious challenge to both government and industry. Early decisions on environmental factors, prompt licensing, and the shortest possible construction schedule would reduce capital costs.

Nuclear Plant Efficiencies

The cycle efficiencies of current light water reactor plants are considerably lower than for modern fossil-fueled generating plants. The net heat rates of light water reactors are usually in the range of 10,000 to 11,000 British thermal units per kilowatt hours. Improved designs, including slightly superheated steam, one or more stages of reheat, and better moisture separation in the turbine cycle, will improve the heat rates of light water reactors—possibly as much as 5 percent. For those plants using cooling towers, however, increased condenser back pressures will tend to degrade heat rates.

High temperature gas-cooled reactors and other advanced concepts with improved steam conditions will have net plant heat rates on the order of 8,200 to 8,600 British thermal units per kilowatt hour.

Nuclear Fuel Costs

Nuclear fuel cycle costs are influenced by many complex operations, most of which are external to the reactor itself. These include costs of mining, milling, conversion, shipping, enrichment, fabrication, and reprocessing.

The capital cost of a nuclear fuel charge for a 1,000-megawatt nuclear plant will be in the order of \$25 to \$35 million, and the carrying charge throughout the fuel cycle for an investor-owned utility could be about one-third of the total fuel cost. The raw material for nuclear fuel must be purchased one to two years before it begins to produce energy. After removal from the reactor, the spent fuel must be cooled three to six months before reprocessing.

The government had a guaranteed purchase price program for U_3O_8, which, however, is being phased out. Therefore, prospecting is now based on the expectation of commercial demand. In response to the surge of nuclear orders in the late 1960's, there has been intensified exploratory drilling which increased reserves, ensured competition, and stabilized ore prices. The conversion of U_3O_8 to uranium hexafluoride (UF_6) is a minor part of the fuel cycle cost, and two privately owned plants in the United States can now perform this function. Fuel enrichment can be accomplished only in government-owned plants at the present time. The cost is about 40 percent of the total fuel cost (not considering fuel inventory carrying charges).

Fuel fabrication costs are almost as large a part of total fuel costs as the enrichment costs. Future savings are expected from process and technological improvements and from handling larger quantities, but there will be higher costs in handling the more toxic plutonium fuels. There is incentive for firms other than nuclear steam system suppliers to engage in reload fuel fabrication by the mid-1970's, when the number of reload batches becomes significant.

The costs of reprocessing spent fuel to extract fertile and fissile material are moderate but will be higher for advanced reactors because of the higher levels of radioactivity. The cost of permanent storage of radioactive wastes must be included in fuel costs determinations. The cost of shipping new fuel from the fabrication facility to the generating station and the highly radioactive spent fuel to the reprocessing facility is nominal, although the cost of shipping the spent fuel is some six or seven times that of shipping the new fuel.

Projections of total fuel costs in mills per kWh for various types of reactors, prepared by the EEI Reactor Assessment Panel in 1970, are listed in table 6.2. It should be noted that several factors other than the direct cost components may have a significant effect on total fuel cycle costs. Examples are the value of recycled bred plutonium as a water reactor fuel and the rate of introduction of fast breeder reactors. It is significant that fuel cycle costs for the fast breeders are projected to be considerably lower than other types in spite of higher fabrication costs.

The values in table 6.2 are in the Panel's forecast of 1975 dollars (and not in the 1968 dollars as are most of the other cost figures in this report) and include all effects on costs (except inflation beyond 1975) anticipated by the panel. For the light water reactor, fixed costs were assumed by the panel for: ore (\$8.00 per pound), enriching (\$26 per kg-unit of separative work), plutonium (\$7.50 per g), fabrication (\$70 per kg U), and shipping and reprocessing (\$45 per kg U). Fuel costs were levelized over the first ten years of operation. An 80 percent lifetime capacity factor was assumed and financing rates assumed were 7 percent per year cost of money and 14 percent per year total fixed charge rate. The estimates for the other reactor types are on a comparable basis.

The Survey's projections of the 1990 fuel cycle cost of nuclear power (LWRs) is given in chapter 19 as 1.6 mills per kilowatt-hour, in 1968 dollars. With current inflation rates that cost expressed in 1975 dollars would be on the order of 2.2 mills per kilowatt-hour. The higher Survey projection, as compared to the EEI projection, reflects the Survey's expectation of constant-dollar cost increases for uranium ore, reprocessing and fabrication, resulting from both high demand and environmental protection requirements.

The plutonium produced in one year from a 1,000 megawatt light water reactor would have a

value of approximately $2 million assuming a plutonium value of $9 to $10 per gram. It may be 20 to 25 years before there will be enough breeder reactors to use all the plutonium that will be produced in light water reactors and it is anticipated that the excess will be recycled in light water reactors. Utilization of plutonium in breeder reactors expands the potential of nuclear fuel reserves by several orders of magnitude. This is one of the primary justifications for developing the breeder reactor.

Operation and Maintenance Costs

Estimated base load operation and maintenance costs for light water reactor plants of various capacities are shown in figure 6.10. These costs include all fixed and variable components of maintenance, supplies and expenses, operating labor, and nuclear insurance.

Quality Assurance

Plant systems and components are classified according to their importance with regard to safety and are designed, fabricated, inspected, and installed in accordance with applicable provisions in recognized codes. Quality can be assured only if sound engineering specifications and good practices are followed by manufacturers, contractors, and owners.

Nuclear economics may be adversely affected if it is not possible to develop major components so that they can be inspected on line or with minimum shut-down periods. Designers of nuclear power plants strive to lay out plants and design equipment that can be readily inspected and tested with little or no shutdown, and with minimum hazard to the staff.

TABLE 6.2

Fuel Cycle Costs for a 1,000-MW Plant[1]

Charge Date	Reactor Type	Fuel Cycle Costs Mills/kWh
1975	LWR	1.7–1.9
1980	LWR	1.5–1.7
1985	LWR	1.4–1.6
1990	LWR	1.4–1.6
1980	HTGR	1.2–1.4
1990	HTGR	1.0–1.2
1985/1990	LMFBR	0.6–0.9

[1] From Report of the EEI Reactor Assessment Panel, April 1970. In 1975 dollars.

ESTIMATED OPERATION AND MAINTENANCE COSTS FOR LIGHT WATER REACTOR PLANTS
1970 PRICE LEVEL

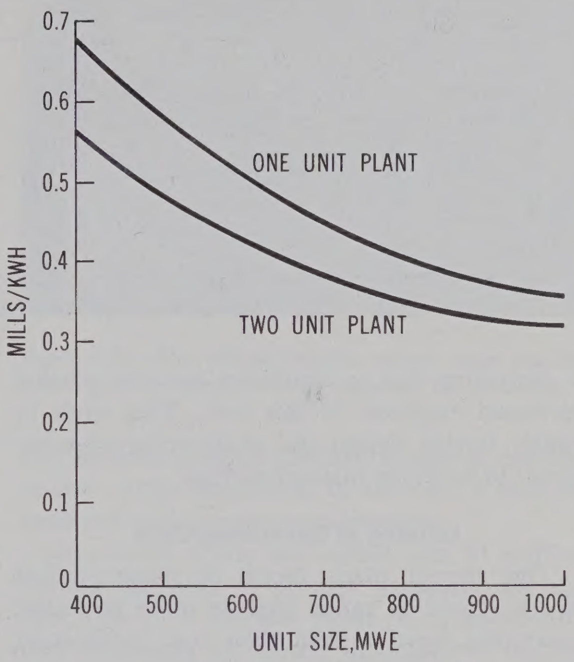


Figure 6.10

Plant Operations

Plant Availability

The on-line availability of nuclear generating facilities is a most important matter, since units out of service not only affect reliability and the adequacy of power supply but also may require the purchase of costly replacement energy. It is important to achieve a high plant availability.

Table 6.3 lists for the 10-year period, 1961–1970, the percent availability by years of nuclear plants in the United States which had been in operation prior to January 1, 1968. The earlier plants required long outages for refueling, but, generally, the time for refueling outages has been decreasing. This can be attributed to better techniques, better tools, improved fuel design, and easier access to the core. Estimates of refueling and scheduled maintenance time now average from one to two months a year. Refueling and normal maintenance are often performed simultaneously. Plant down-time for equipment inspection and material surveillance

TABLE 6.3

Commercial Nuclear Reactor Availability Factors

	Availability Factor in Percent [1]									
	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970
Dresden	40	81	81	83	83	97	60	67	67	97
Yankee (Rowe)	87	68	79	91	76	90	92	88	83	85
Indian Point		61	71	48	64	68	81	92	93	27
Big Rock Point			48	43	30	75	90	81	92	86
Shippingport	80	88	89	0	0	96	97	99	77	99
Humboldt Bay			83	89	80	89	91	93	90	88
San Onofre							63	44	79	84
Haddam Neck							81	91	94	81

[1] Availability factor = percent of year reactor was available to produce power.

is increasing due to regulatory agencies placing increased emphasis in this area. This tends to justify further design and engineering improvements to minimize inspection time.

Loading of Generating Units

The annual plant factor of nuclear-fueled plants should be rather high in order to realize maximum benefits from their low incremental production costs. As more efficient nuclear plants are added, the first nuclear plants will be operated at decreasing annual plant factors. Some nuclear plants after the initial break-in period may be operated at annual plant factors of about 80 percent during the initial years of their service lives, depending on system load characteristics and the composition of other generating capacity. Over their lives, however, it is anticipated that few plants will be operated at average annual plant factors as high as 70 percent.

Operating experience with present nuclear plants indicates they are able to handle load swings without difficulty. The high temperature gas reactor and liquid metal fast breeder plants now being designed with steam conditions similar to modern fossil-fueled plants should also have good load following characteristics.

Performance During System Disturbance

Nuclear units are not designed for continuous low-capacity operation. However, by providing an appropriate control system, the load on a unit may be reduced from full load to station service load. This may be of increasing significance since core output power can be maintained at low levels, permitting the unit to resume normal operation in a much shorter time than a large fossil-fueled unit.

Nuclear plant safety systems are so designed that a unit can be shut down quickly and safely. Core decay heat can be removed by various methods using power from independent on-site generation or from other sources. On-site generation usually consists of automatically starting diesel engines. To operate all equipment essential to the safe shutdown of a plant with 1,000-megawatt reactors, a diesel generator unit of about 2.5 megawatts would be required for each nuclear unit, plus one or more spare units.

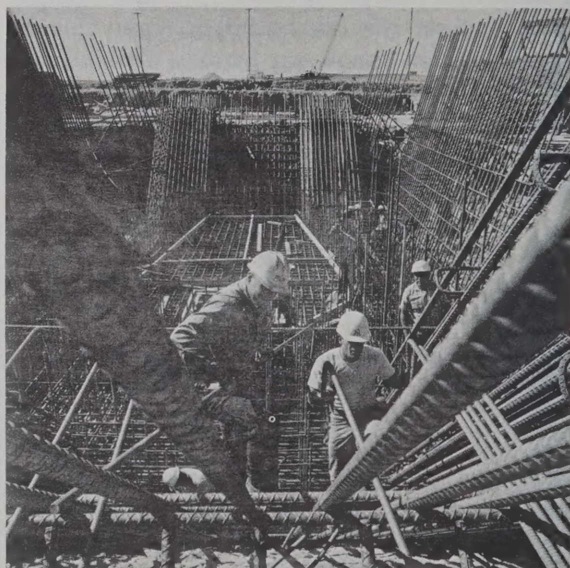


Figure 6.11—A total of 16,000 tons of reinforcing steel will be installed in the 1,060-MW Unit No. 1 of PG&E's Diablo Canyon plant.

Computer Applications in Nuclear Plant Operation

Computers are being used extensively at nuclear plants for data logging, data reduction, and for on-line core nuclear analysis. The complexity of operating parameters at nuclear facilities requires the help of a computer for rapid and complete assessment of the status of the plant. Improvements in computer hardware design and ability may be required before widespread use of the computer is practical for direct digital plant control.

Personnel Requirements

A staff of 50 to 75 is now required for the operation, maintenance, and on-site technical support of a single unit nuclear plant and 75 to 100 are needed for a two-unit plant. Manning requirements depend largely on the extent of maintenance performed by organizations outside the plant. There is a wide variation in personnel requirements among companies depending on the organization structure. The unit size does not have an appreciable effect on the number of persons required.

The total number of on-site personnel required to operate nuclear power plants in the United States will increase from an estimated 2,100 in 1970 to over 20,000 in 1990. These estimates do not include maintenance personnel required to repair major equipment failures. Of the total personnel, approximately 45 percent are plant operators, 25 percent perform maintenance, and the remainder provide management, engineering, and other services.

The number of persons performing management and technical support of nuclear power plants at an electric utility headquarters will vary widely depending on the extent of utility involvement in nuclear power, utility policy regarding the performance of certain functions in-house or through contractors, and the joint support of central nuclear technical staffs by groups of utilities. Estimates of the total number of utility headquarters-based nuclear-oriented personnel required by 1990 range from 3,000 to 6,000.

Training of Personnel

Persons with nuclear skills can be obtained from those colleges and universities which have graduate and undergraduate training programs and from technical institutes. Personnel may

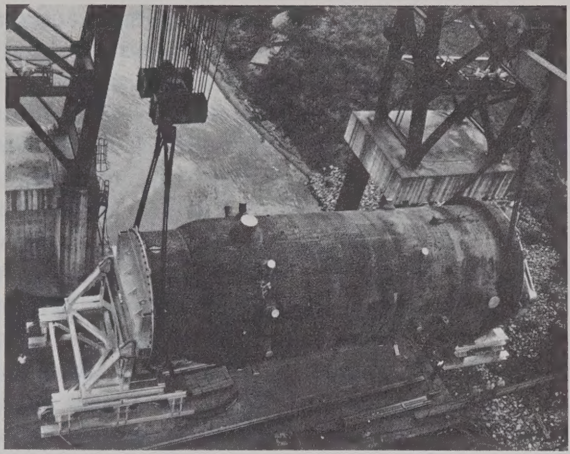


Figure 6.12—This 825-ton nuclear reactor vessel for the Browns Ferry plant is being prepared for shipment.

also be developed by special training of existing or new utility employees. In any case, a comprehensive training program is required.

An electric utility may spend over $1 million in training costs to prepare personnel for the operation of a nuclear plant. It is mandatory that employees be trained in numerous technological areas, particularly nuclear safety, to meet licensing requirements. At various training centers computers are being used for plant simulators in training and retraining operators. Training required for various categories of utility employees involved in nuclear operations is summarized below.

The training of management and headquarters personnel is usually on a part-time basis and can involve nuclear seminars, graduate level courses, programs by industrial organizations, and assistance by consulting organizations.

Supervisors, senior operators, and usually a few junior operators are examined for licensing by the Atomic Energy Commission prior to initial operation of the nuclear plant to which they will be assigned. Licensing of most junior operators, however, generally takes place after they have accumulated experience in operating the plant under direct supervision of the licensed senior operators and supervisors.

Nuclear Power Environmental Considerations

Siting Criteria

The safety of the public is a primary concern in locating nuclear plants but many other fac-

tors also influence their location, design, and operation. Since nuclear fuel transportation costs are small, nuclear plants can be most advantageously located near load centers to minimize transmission distance and maximize reliability. However, as a precautionary measure, nuclear plants normally are not located near dense population concentrations. Nuclear plants should have good accessibility for large and heavy components by heavy duty highway, railroad, or barge route to facilitate construction and servicing. Recently, procedures for on-site fabrication of the reactor vessel of BWR's have been developed to alleviate the transportation problems. The availability of adequate cooling water is another principal factor in selecting a nuclear site.

As a part of, and in addition to, the detailed plant safety analysis discussed later, the AEC considers numerous environmental factors in reviewing the acceptability of a proposed nuclear plant site. Population densities at varying distances from the plant are evaluated in relation to the capacity and type of the proposed installation, as well as the containment system and engineered safety features to be used. Thorough examination of pertinent seismological and geological factors is required. The plant must be designed to withstand the largest probable earthquakes. The effects of possible flooding due to unusual weather conditions, tidal waves, dam failure, etc., are considered. Meteorology also plays a role in the site consideration, as wind and weather patterns affect the permissible release rate for gaseous effluents.

There have been proposals to place nuclear plants underground in urban locations to mini-

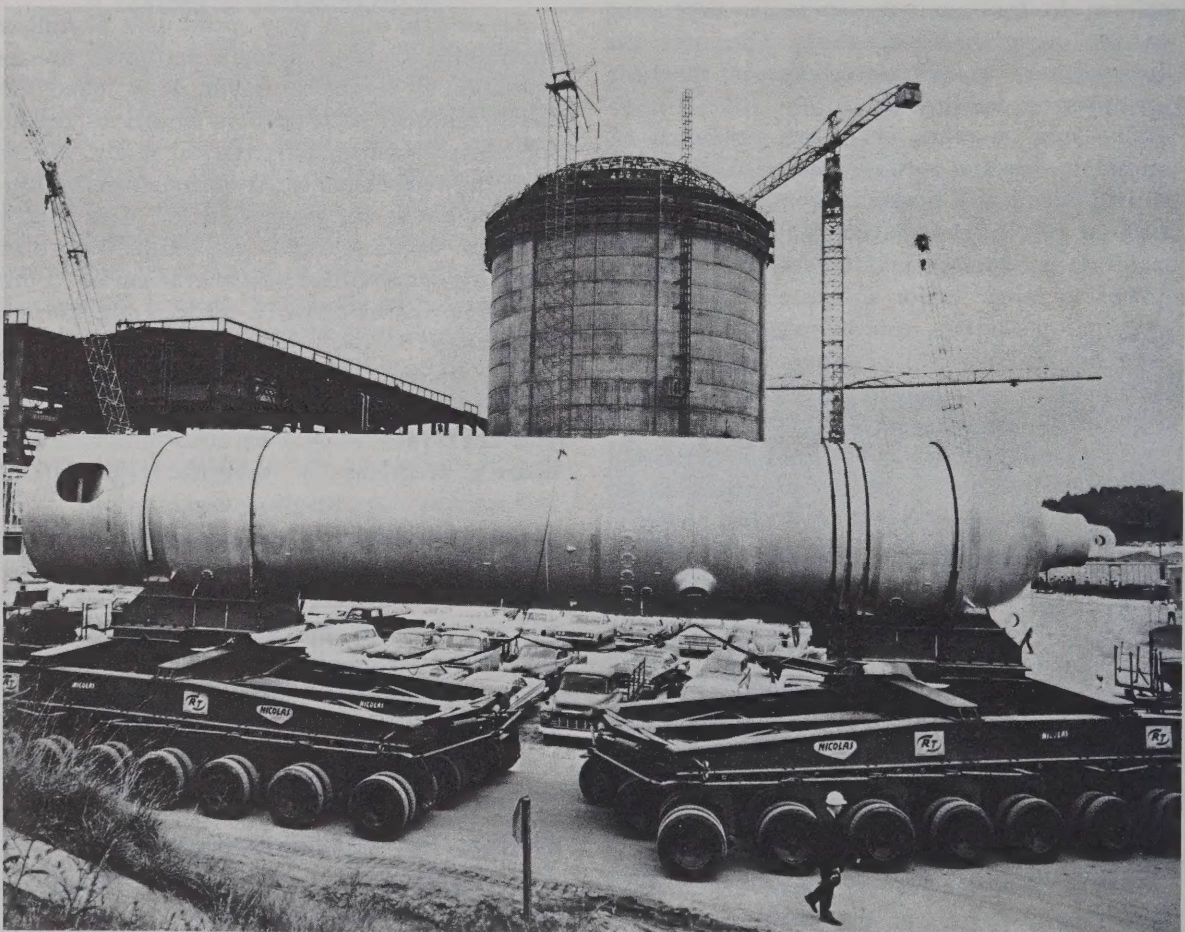


Figure 6.13—Steam generator for 841-MW Unit No. 1 of Duke Power Company's Oconee station in South Carolina weighs 570 tons and is 73 feet long.

mize transmission distances, conserve valuable surface area, and enhance safety. Several small nuclear plants have been placed underground in Europe, taking advantage of local geologic features. However, this siting approach is not widespread. Another potential solution to the siting problem in metropolitan areas along the coast is to locate plants offshore on islands, on the sea floor, under the continental shelf, or on floating platforms.

The appearance of generating stations is becoming more important because of the growing public awareness of esthetic values. Nuclear plants can be architecturally as pleasing to the eye as other large structures.

Effects on Water Resources

Due to the lower thermal efficiency of present nuclear plants, as compared with fossil-fueled plants, and the resultant rejection of more heat to the cooling water per unit of power produced, the potential effect of this heat on aquatic life is receiving considerable attention. This problem is discussed in more detail in chapter 10.

Reactor Safety

Development of Radiation Standards

In the United States, the Federal Radiation Council (FRC) [1] has provided guidance in the development of radiation standards for all executive agencies of the government. The principal functions of the Council were to advise the President on radiation protection matters and to coordinate radiation protection within the Executive Branch of the government, especially with respect to uniformity of radiation protection standards and Federal-State cooperation. The recommendations of FRC were developed with the assistance of appropriate Federal agencies, the National Academy of Sciences, the National Council on Radiation Protection and Measurements, and consultants selected for expertise in various areas. FRC recommended limits of exposure of the human body to radiation. Limits on concentrations of radioactive materials in air and water are set so that continuous exposure to them by the average person will not result in damage to the whole body or any organ. In 1970, the functions of the FRC were transferred to the newly established Environmental Protection Agency (EPA).

The AEC's regulation [2], developed within the framework of the FRC recommendation sets limits on concentrations and/or quantities of radioactivity that may be released to the air and water from a nuclear power plant, specifying how releases must be controlled and monitored.

On June 4, 1971, AEC issued a proposed rulemaking which sets forth new numerical guides to keep levels of radioactivity in effluents to unrestricted areas as low as practicable. Under these proposed guides radioactivity released from light-water-cooled reactors would generally be less than five percent of average exposures from natural background radiation. This level of exposure is about one percent of Federal radiation protection guides for individual members of the public.

The Advisory Committee for Biology and Medicine (ACBM), comprising knowledgeable persons from universities and industry, advises the AEC on medical and biological research and health. The ACBM has concluded that presently available data gives an adequate foundation of knowledge for setting public safety standards on radiation levels and emissions. The committee believes that future research will reveal that present standards are conservative.

Safety Protection for Nuclear Reactors

Reactor safety is assured by systematic evaluation of the proposed design in terms of adequacy of systems to control possible accidents, by multiple safety reviews by independent groups of experts in the AEC licensing process, and by a system of surveillance and periodic inspection during construction and operation of each facility.

There are three general courses followed in the design of a nuclear power reactor. First, to assure safety, the major features of the plant are designed to insure a very low probability of accidents. This is illustrated by the provision of successive barriers to the escape of fission products. Secondly, safety features to prevent accidents are incorporated, such as emergency cooling systems, redundancy in controls and shutdown devices, and the provision of emer-

[1] Established by Executive Order No. 10381 on August 14, 1959; status confirmed by PL 86–373, approved September 23, 1959.

[2] 10 CFR, Part 20, "Standards for Protection Against Radiation".

gency power sources. Thirdly, safety systems are provided to limit the consequences of any accident that might somehow occur.

Radioactivity in Condenser Cooling Water

Radioactivity in condenser cooling water is carefully monitored and regulated in accordance with plant licensing requirements and should have no significant effect on the environment. The EPA monitors, with a network of sampling stations, important surface waters in a continuous evaluation of the physical, chemical, biological, and radiological characteristics. One of the radiological effluents of particular interest is tritium, monitored by 39 of these stations located downstream from nuclear facilities. In addition, tritium is monitored at 70 public water supplies and 8 precipitation collection stations.

Radioactive Discharges to the Atmosphere

The quantity of gaseous effluents from a nuclear plant is insignificant compared to the amount from a fossil-fueled plant of equal rating; however, because nuclear plant effluents include radioactive gases, the releases are closely regulated and monitored. Radioactive effluents may in some cases be held for a few months to permit the decay of isotopes before being released to the atmosphere under conditions for maximum dilution so as to minimize contamination. Existing BWR plants emit more gaseous radioactivity than PWR's, although at levels far below limits established by the National Council on Radiation Protection and Measurements (NCRP). However, equipment is now available to reduce the BWR discharges to the levels attained by PWR's.

It is not possible to detect by generally accepted techniques any biological effect on the surrounding population of reactor radioactive effluents at the low levels allowed by AEC regulations. The slight increase in radiation level from the radioactive gases released by commercial reactors is usually so small as to be not measurable. In all cases the actual amounts are only a small fraction of the natural radiation background over an extended period of time and have been well within the AEC requirements and FRC guidelines.

The AEC, EPA, and some states monitor the atmosphere in the vicinity of nuclear plants to detect any increases in radioactivity levels. There are a number of sampling stations across the country to detect any radioactivity changes in milk. A background of 30 years of experience with nuclear facilities has provided extensive knowledge about radioactivity, its effects and its control, from which to establish a sound base for setting standards and permissible concentrations in the environment. Environmental monitoring will continue to be a valuable aid in assuring that nuclear power does not contribute significantly to environmental radiation levels.

Reactor Waste Management

All but a very small quantity of the total radioactivity produced in a reactor core is retained in the fuel elements and is eventually removed from the reactor site as part of the refueling operation. After spent fuel is reprocessed, radioactive wastes are stored in appropriate containers and placed in underground vaults under permanent Federal supervision. Essentially all of the fission products that escape from the core into the primary coolant system remain within that system. The minuscule amounts that escape from the reactor cooling system through leakage, or during servicing, are passed through a waste treatment system in which the radioactive portions are separated by such methods as ion exchange and evaporation preparatory to permanent offsite storage. Of the very small amount of radioactive material that remains in the dischargeable waste, a combination of delay to permit decay and dilution to limit concentrations reduces the effects on the environment to a minimum.

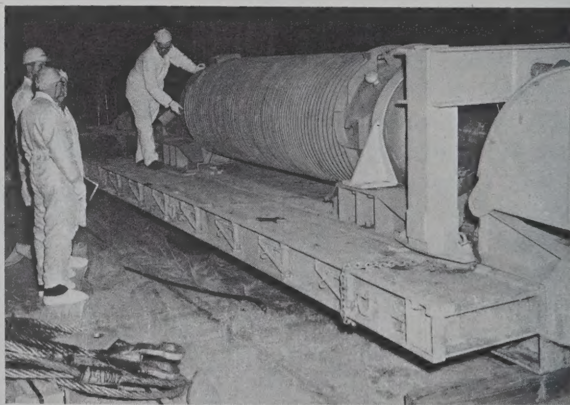


Figure 6.14—Consolidated Edison Company's specially designed casks, containing spent reactor fuel elements, being prepared for shipment to reprocessing plant.

Possible Future Reactor Types

Advanced Converter and Low Gain Breeder Concepts

The promise of better energy conversion ratios, better economics, and the need to conserve fuel resources has led to efforts to develop advanced converters. Attention has been concentrated on the high temperature gas-cooled concept and the seed-blanket light water breeder concept.

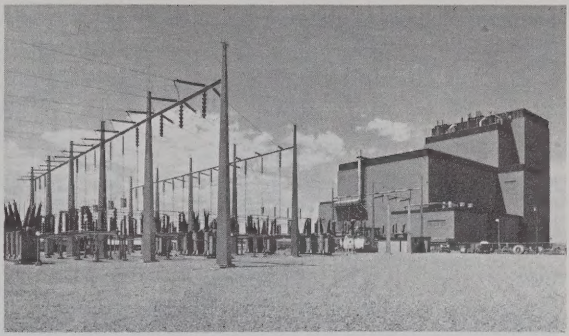


Figure 6.15—Fort St. Vrain, the Nation's first large nuclear plant scheduled to utilize a high temperature, gas-cooled reactor. It is also the first in the U. S. for which a prestressed concrete reactor vessel was used.

High Temperature Gas-Cooled Reactor

Of the technically feasible advanced converters, the high temperature gas-cooled reactor (HTGR) has the greatest potential for early commercial application. An advanced converter can produce more new fissile material than conventional thermal reactors but not as much as "breeders" which will produce more new fissile material than is consumed. The first HTGR constructed in the United States was Peach Bottom No. 1 in Pennsylvania, a 40-megawatt unit placed in commercial operation in 1967. Construction is now under way on a second HTGR, the Fort St. Vrain No. 1 unit of Public Service Company of Colorado, rated at 330 megawatts and scheduled for service in 1972. Designs have been prepared and orders placed for units of 1,160 megawatt capacity.

The HTGR is a graphite moderated thermal reactor concept cooled with helium which reaches a temperature of some 1,400°F, as it passes through the reactor core. The circulation of the helium through the steam generators produces high pressure steam at a temperature of 1,000°F. and, with the application of a reheat steam cycle, modern fossil fuel plant cycle efficiency can be attained. The HTGR, with its inherent higher plant efficiency and better rate of conversion of fertile to fissile material, provides an opportunity for better uranium and thorium utilization pending the development of breeder reactors. The higher efficiency also reduces heat rejection to the environment to a level somewhat below that of modern fossil-fueled steam-electric plants.

Studies are under way on plans to utilize the high temperature helium used for cooling the HTGR to drive closed cycle gas turbines. Under the proposals, the gas turbines would be designed to produce base load power and would eliminate the steam cycle in the generation process. An advantage of the scheme is that waste heat would be discharged at high temperatures. This could make possible the economical use of dry cooling towers, since relatively small volumes of air would be required for waste heat dissipation with the large differential above ambient air temperatures. Beneficial uses of the waste heat may also be possible, such as for desalinization of water and for space heating.

The fuel used in an HTGR in the United States is in the form of highly enriched (90 percent U-235 isotope) uranium dicarbide microspheres covered with coatings of carbon. The fertile material is coated thorium dicarbide microspheres. The Fort St. Vrain core will consist of graphite prismatic columns having holes to contain the fissile and fertile particle fuel compacts and coolant channels to permit the passage of helium.

Light Water Breeders

The thorium-uranium-233 fueled seed-blanket light water breeder reactor (LWBR) concept offers a potential conversion ratio significantly higher than present light water reactors or other advanced converters studied by AEC. Some fabrication work has been done on an LWBR core. An LWBR does not require major changes in light water reactor technology and there are few engineering uncertainties in developing a workable and reliable system. The LWBR will not produce an excess of fissile material for fueling additional reactor capacity as rapidly as is predicted for a fast neutron breeder system.

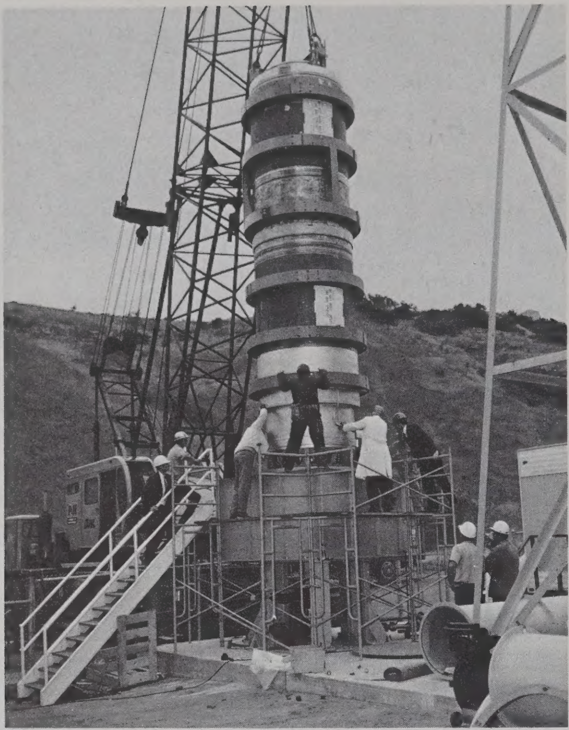


Figure 6.16—The first of 12 steam generator modules to be completed for the Fort St. Vrain station is shown being prepared for flow and vibration tests.

Molten Salt Breeder Reactor

The MSBR concept, a graphite-moderated thermal reactor, uses a fuel-bearing primary liquid (molten salt) that circulates through a graphite core structure where fission takes place and heat is generated. As the fluid leaves the core, it becomes subcritical and goes through a heat exchanger where heat is transferred to a secondary heat-transport fluid. The fuel would probably be uranium tetrafluoride in a carrier mixture of lithium-7, beryllium fluorides with a melting point of about 850°F. With a circulating fuel system, a side stream would be processed continuously, removing bred protactinium and fission products and maintaining fuel quality so that refueling shutdowns would not be required. The secondary heat-transport system might use sodium fluoroborate salt as a working fluid. The breeding ratio of the MSBR would probably be about 1.05,[3] with a doubling time [4] of approximately 21 years.

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[3] Breeding Ratio $= \dfrac{\text{Fissile Material Produced}}{\text{Fissile Material Consumed}}$

[4] Doubling time is the time required to produce enough excess fissile material to fuel a second reactor.

Fast Neutron Breeder Reactors

The successful development of fast breeder reactors will make the nation's reserves of uranium and thorium an almost unlimited source of energy for the generation of electric power. Breeder development will also have the effect of making the use of low-grade ore economically acceptable, since breeders will increase fuel utilization from a few percent in present-day reactors to over 50 percent in fast breeders. The high gain breeders will produce an excess of fissile material for the fueling of new reactors at a rate which may match the 10-year doubling growth of the electric industry. The two types of fast breeders that are of major interest in this and other countries are the sodium-cooled and gas-cooled breeders described in the following sections.

Liquid Metal Fast Breeder Reactor

As with most countries involved in significant reactor development programs, the United States has chosen the liquid metal fast breeder reactor (LMFBR) as its highest priority civilian breeder reactor development program. The Enrico Fermi sodium-cooled reactor at Lagoona Beach, Michigan, was the first privately owned fast neutron breeder reactor in the United States. This 60.9-megawatt unit reached criticality in August 1963. It was operated at progressively higher levels of power output in a planned test program until, in 1966, a fuel meltdown occurred when several pieces of zirconium attached to the conical flow guide broke loose and partially blocked four fuel channels. The unit was repaired and returned to operation and further testing in 1970.

In the LMFBR, the sodium coolant leaves the reactor core at a temperature of about 1,100°F. and is extremely radioactive. Heat is transferred in an intermediate heat exchanger to a secondary non-radioactive sodium system which, in turn, produces steam for the turbine in steam generators. A net plant thermal efficiency of approximately 40 percent can be achieved. Major efforts are being made to develop LMFBR plants having a high degree of safety, reliability, availability, maintainability, and economy. These objectives are expected to be achieved in time to have the first commercial plant available to operate by the mid-1980's.

Breeding ratios of about 1.4 are predicted. Since an LMFBR would produce more fissile fuel than it consumes, a self-sustaining breeder fuel cycle can be based on the use of recycled Pu with U-238 added as the fertile material. Fuel will probably be in pellet form encased in stainless steel tubing of smaller diameter than the fuel rods for light water reactors. The active core of the breeder reactor will be surrounded on all sides by a blanket region composed of bundles of rods containing uranium oxide depleted in U-235 isotopic content (enrichment plant tailings). The escaping neutrons will be absorbed in the U-238 isotope of uranium, thereby producing plutonium.

The LMFBR concept, using sodium as a coolant, possesses good nuclear characteristics, a high boiling point which permits low pressure and high temperature operation with resultant good thermal efficiency, excellent heat transfer characteristics, a large heat capacity, low requirements for pumping power, and relative freedom from corrosion in the absence of air and water. The LMFBR promises high breeding ratios and a doubling time of some 8 to 10 years. Disadvantages of sodium are prolonged radioactivity after shutdown, chemical activity with air and water, and opacity—a disadvantage to maintenance. At normal maintenance temperatures, the coolant solidifies. In addition to creating problems during component maintenance, the subsequent remelting of the coolant prior to plant operating requires special procedures not required of water and gas cooled reactors.

The AEC has a comprehensive LMFBR Program Plan to develop the required technology for design, construction, and operation of safe, reliable, and economic fast breeder reactors in central station nuclear power plants. A major fast neutron test facility is scheduled for operation near Richland, Washington, in 1974 to help develop nuclear fuel that can withstand the high burnup required for economic operation of fast breeders. Prototype components are tested at the Liquid Metal Engineering Center at Canoga Park, California, and the Experimental Breeder Reactor-2 (EBR-2) is located at the National Reactor Testing Station in Idaho for preliminary fast neutron irradiation of fuels and materials. Other reactors will be used to provide accurate nuclear data on core criticality and safety as well as for economic analyses of various cores.

There are several significant factors to be considered in assuring the safety of LMFBR's. These include the effects of high-energy short-lived neutrons on materials, the need to prevent the possibility of critical reassembly of the fuel during core meltdown, the effect of voids that might form in the sodium coolant (providing increased reactivity), and chemical reactions in case of contamination of the sodium by air and water.

Three industrial groups involving the electric utility industry and three reactor suppliers signed contracts with the AEC in early 1970 for technical and cost studies leading toward proposals to construct LMFBR demonstration plants. The construction of several demonstration plants in the 300–500 megawatt range at intervals of about two years, with initial plant operation beginning in the late 1970's, is required to provide a sound basis for translating LMFBR technology to the nuclear industry for commercial utilization. Legislation has been proposed to increase Federal appropriations for financial assistance to the initial demonstration plant. Broadly based management and technical committees composed of representatives of the electric utility industry have been established to work with the AEC in developing a program for industry support of the demonstration plants. Also, President Nixon in his June 4, 1971, message on energy included a commitment to complete the successful demonstration of the liquid metal fast breeder reactor by 1980; and later, in September 1971, he announced the intention to initiate a second LMFBR unit.

Gas-Cooled Fast Breeder Reactor (GCFBR)

The use of helium for cooling in a GCFBR offers the possibility of providing good neutron economy, doubling times comparable to the LMFBR, high temperature, efficiency, and ease of maintenance (due to the coolant being low in radioactivity, transparent, and chemically inert). Disadvantages are the requirement that forced circulation be maintained during emergencies, low heat capacity of the core, the relatively high pressure, and high pumping power

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requirements. Reactor pressure would be about 1,250 psi and gas temperature in the reactor about 1,000°F. The fuel would be composed of small metal-clad ceramic rods.

Current designs contemplate enclosing the reactor and steam generator in a prestressed concrete reactor vessel which would be housed in a steel-lined concrete containment building. A number of electric utilities are supporting studies for a demonstration plant to establish GCFBR practicality. Conceptual design studies have been completed for a 300-megawatt demonstration plant with a net plant efficiency of about 38 percent.

CHAPTER 7

CONVENTIONAL AND PUMPED STORAGE HYDROELECTRIC POWER

Introduction

Conventional hydroelectric developments use dams and waterways to harness the energy of falling water in streams to produce electric power. Pumped storage developments utilize the same principle for the generating phase, but all or part of the water is made available for repeated use by pumping it from a lower to an upper pool. At the end of 1970, conventional hydroelectric capacity totaled 52,323[1] megawatts compared to only 3,689 megawatts of pumped storage capacity. During the next 20 years, however, the installation of pumped storage capacity is expected to exceed greatly the installation of new conventional capacity. By 1990, conventional hydroelectric capacity is expected to total approximately 82,000 megawatts and pumped storage capacity about 70,000 megawatts. Existing conventional and pumped storage capacity and projections for 1990 are shown by National Power Survey regions on figure 7.1.

Over the years, hydroelectric plants have provided a substantial but declining proportion of the nation's electric power supply. This trend is expected to continue despite the construction of many large pumped storage plants. Hydroelectric plants, which now account for 16 percent of total generating capacity, are expected to provide about 12 percent of the total capacity in 1990.

Operating Characteristics

Hydroelectric power plants have distinct advantages over thermal plants. Operation and maintenance costs are relatively low, and in many instances, the plants can be designed for automatic or supervisory control from a remote location. The cost of fuel, a major expense in thermal installations, is not an item in the operational costs of hydroelectric plants except for the consumption of pumping energy at pumped-storage plants. Hydroelectric installations have long life and low rates of depreciation. Unscheduled outages are less frequent and downtime for overhaul is of short duration because hydroelectric machinery operates at relatively low speeds and temperatures and is relatively simple. A hydroelectric unit is normally out of service about 2 days per year due to forced outages and about 1 to 2 weeks for scheduled maintenance. The average outage rates of modern steam-electric units are several times greater.

The ability to start quickly and make rapid changes in power output makes hydroelectric plants particularly well adapted for serving peak loads, and for frequency control and spinning reserve duty. If operating at less than full load, they are, in most cases, able to respond very rapidly to sudden demands for increased power. Their ability to supply starting power to steam-electric plants following a major power failure has been demonstrated on several occasions in recent years. There are no emissions that would affect air quality and there are no heat discharges to the receiving waters. Conventional hydroelectric developments do not consume natural fuel resources. Under some circumstances, they can provide a source of replacement power for use when generation at fossil-fired plants might need to be reduced during air pollution alerts. They occupy large areas of land, however, and cause short- or long-term changes in stream regimens, including such items as reservoir drawdowns, so they are often strenuously opposed on esthetic or ecological grounds.

Conventional Developments

Many associated benefits are provided by conventional hydroelectric developments. Reservoirs are used extensively for recreation, and may

[1] Includes 682 MW of industrial capacity.

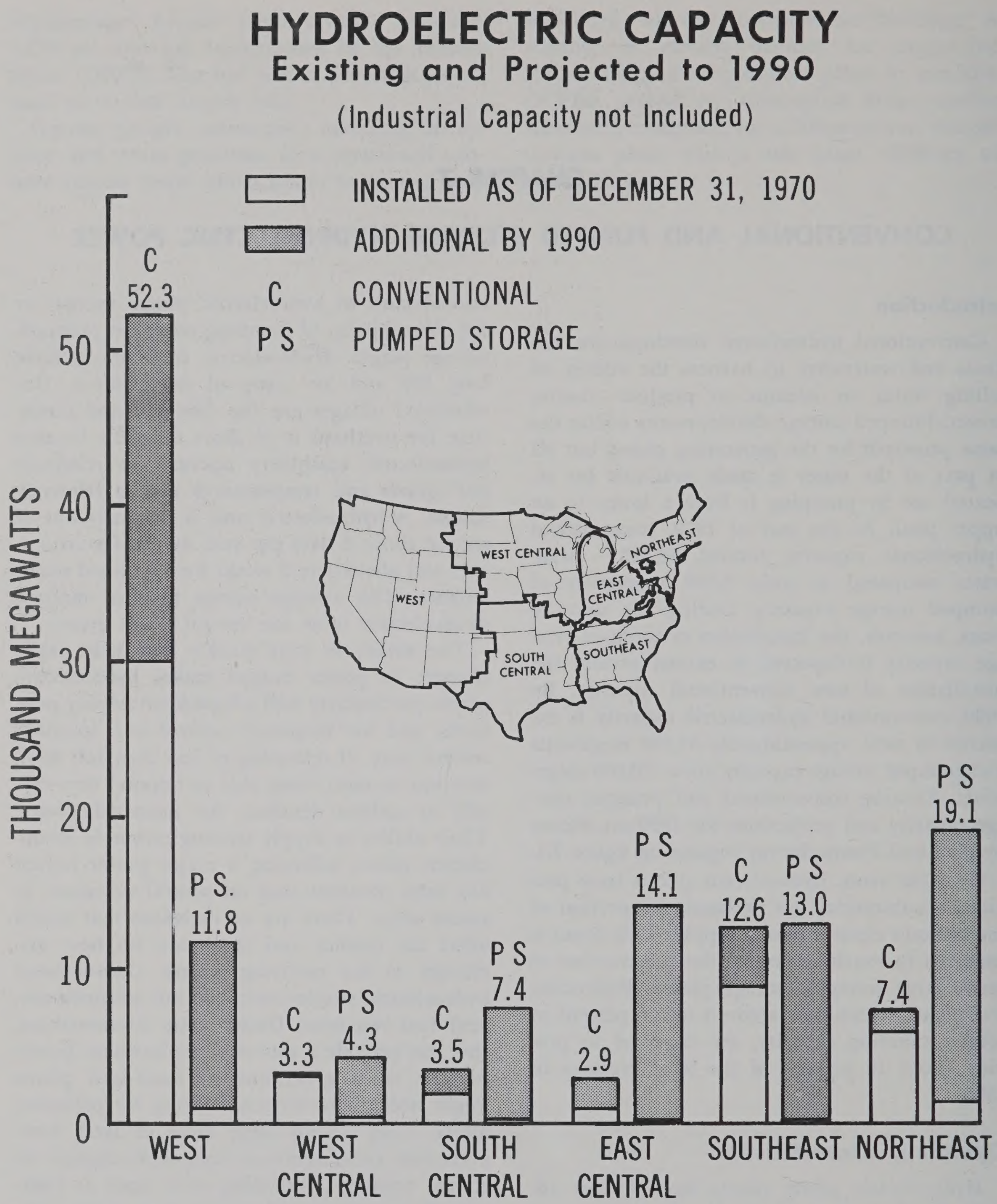


Figure 7.1

provide water for domestic and industrial water supply and condenser cooling water for thermal-electric plants. Some projects provide flood control, and some are operated to supplement natural flows during low-flow periods to provide benefits related to such non-power functions as water quality control, navigation, municipal water, irrigation water, and fish and wildlife.

Streamflow regulation by reservoirs may have adverse as well as beneficial effects, but special

measures can usually be taken to minimize adverse effects. For example, a reregulating reservoir may provide uniform flows downstream from a peaking hydroelectric plant. Facilities may be constructed to provide for passage and protection of anadromous fish runs. However, even with fish passage facilities, the cumulative effect of a series of dams may be substantial reductions of such runs, as has been the case on the Columbia River. At some reservoirs fish passage has not been successful but the runs are being maintained with fish hatcheries financed by the owner of the power facility.

In deep reservoirs the lower levels may be low in temperature and largely devoid of oxygen, particularly during late summer months. Releases of waters from the deeper levels could benefit downstream cold water fisheries such as trout and salmon if oxygen demands are met. On the other hand, release of colder waters could adversely affect warm water fisheries. At some projects, such as Gaston and Roanoke Rapids on the Roanoke River in North Carolina, submerged weirs were constructed above the power intakes in order to skim water from the upper layers of the pools where the dissolved oxygen content of the water is greater. At the Hartwell project on the Savannah River, and at certain other projects, vacuum breakers, installed in the draft tubes to prevent cavitation, have also provided for some reaeration of downstream flow releases. The hydro-turbine reaeration procedure has been used with moderate success at projects on several streams in Wisconsin, including the Flambeau, Wisconsin, and Fox Rivers. Other projects, such as Oroville on the Feather River in California, have multi-level intakes which permit the withdrawal of water from various levels of the reservoir to provide downstream flows with optimum water temperatures and oxygen content. The Corps of Engineers has installed air diffusers at the Allatoona reservoir on the Chattahooche River in Georgia to improve water quality through destratification. They have provided significant increases in the oxygen content of water discharged from the reservoir. Some experimental use has been made of special spray type valves for reaeration of downstream releases to improve oxygen content. At some dams, spillway discharges have caused downstream waters to be supersaturated with nitrogen, resulting in adverse effects on fish. Additional research, including comprehensive ecological evaluations, is needed on means of improving the quality of water released from deep reservoirs.

Pumped Storage Developments

There are two major categories of pumped storage projects: (1) developments which produce energy only from water that has previously been pumped to an upper reservoir, and (2) developments which use both pumped water and natural runoff for generation. Although pumped storage projects may have conventional hydroelectric generating units and separate pumps, most developments utilize reversible, pump-turbine units. Some plants contain both conventional and reversible units. In such cases, the reversible generating units are considered herein as constituting pumped storage developments.

A pumped storage plant has the same favorable operating characteristics as a conventional hydroelectric plant—rapid start-up and loading, long life, low operating and maintenance costs, and low outage rates. The ability of a pumped storage plant to accept or reject large blocks of load very quickly makes it much more flexible than a steam-electric plant, either fossil-fueled or nuclear, in following the load fluctuations which occur on a minute-to-minute basis in an electric system. This ability to follow the changes in the system load so as to furnish a portion of the peaking requirements permits more uniform and efficient loading of the fossil-fueled and nuclear units. Also by pumping in the off-peak hours, the plant factor of the base load thermal units is improved, thus reducing severe cycling of these units and improving their efficiency and durability.

Pumped storage plants can play an important role in assuring system reliability. In recent FPC licensing actions, considerable attention has been given to assuring project designs that will permit operation of units as spinning reserve and allow the loading of units in minimum time. When properly designed, a high-head pumped storage unit may operate as a synchronous condenser, with the spherical valve closed, and be fully loaded in about one minute. Units in the lower head ranges may be operated as synchronous condensers without the use of cut-off valves and have an even faster response to load changes. Also, a unit can be operated at 50

percent to 60 percent of full load and have the ability to pick up the remainder of its capacity in about 15 seconds. This provides an ideal source of spinning reserve capacity to protect a system at a time when generating capacity is suddenly lost. In the event of an emergency on the system during the pumping cycle, the system load may be reduced quickly merely by dropping the pumping load. By rapidly picking up full generating load, approximately twice the capacity of the plant can, in effect, be made available to the system to meet a generation deficiency occurring during the pumping cycle.

Operating experience at the Muddy Run project on the Susquehanna River in Pennsylvania shows that, if the units are in a normal ready condition, one of the 100-megawatt units can be started in three minutes and all eight units in the plant can be started in 12 minutes. The changeover time from pumping to generating cycle is 5½ minutes for one unit or 20 minutes for the plant. In a recent test, two units were tripped while in the pumping cycle and two others were immediately started in the generating mode, for a net increase in power of 460 megawatts in approximately six minutes.

In normal operation of the Cabin Creek plant in Colorado, shown in figure 7.2, a period of 10 to 13 minutes is required to synchronize and fully load each of the two 150-megawatt units. In an emergency, it is possible to synchronize and load both machines simultaneously in approximately the same time period. The time required for the plant to change from pumping to generating or vice versa is about 25 minutes.

The design of the eight 250-megawatt units planned for the Cornwall project, New York, provides for changeover from full pumping to full generation in 158 seconds and from full generation to full pumping in 17 minutes. Design for a relatively short turn around time from pumping to generating is usually feasible but, because of pump starting problems, the turn around time in the reverse direction is usually longer, as illustrated by the Cornwall design.

Use in Serving Loads

Hourly loads of a southern utility system for the peak week in August 1968, a week when extremely hot weather was experienced, are shown in figure 7.3.

Figure 7.2—The Cabin Creek project of the Public Service Company of Colorado, a 300-megawatt pure pumped storage development utilizing a gross head of 1,199 feet, went into operation in 1967.

The usual practice is to use new, efficient steam-electric units, either fossil-fueled or nuclear, to serve the base portion of the load. The less efficient steam-electric capacity, usually the older equipment, is used to serve the higher portions of the load and therefore operates at a lower capacity factor. Normally, conventional and pumped storage hydroelectric capacity is used to serve the peak portions of the load, although gas turbines may be used to serve sharp peaks of short duration. Figure 7.3 is an illustration of normal practice.

In some cases, conventional hydroelectric capacity may operate in lower portions of the load. Some plants must operate at high capacity factors because the rate of flow releases must be relatively constant in the interest of navigation or other purposes. Also, run-of-river plants operate at high capacity factors during periods when available streamflows permit.

Because of losses in the pumping-generating cycle, pumped storage plants require approximately three kilowatt-hours of pumping energy to provide two kilowatt-hours of generation. Therefore, the availability of a dependable supply of pumping energy is essential. Equally important is the necessity of constructing reservoirs with sufficient storage capacity to fit the pumping and generation requirements. For the load shown on figure 7.3, steam-electric energy would be available only about 10 hours each weekday

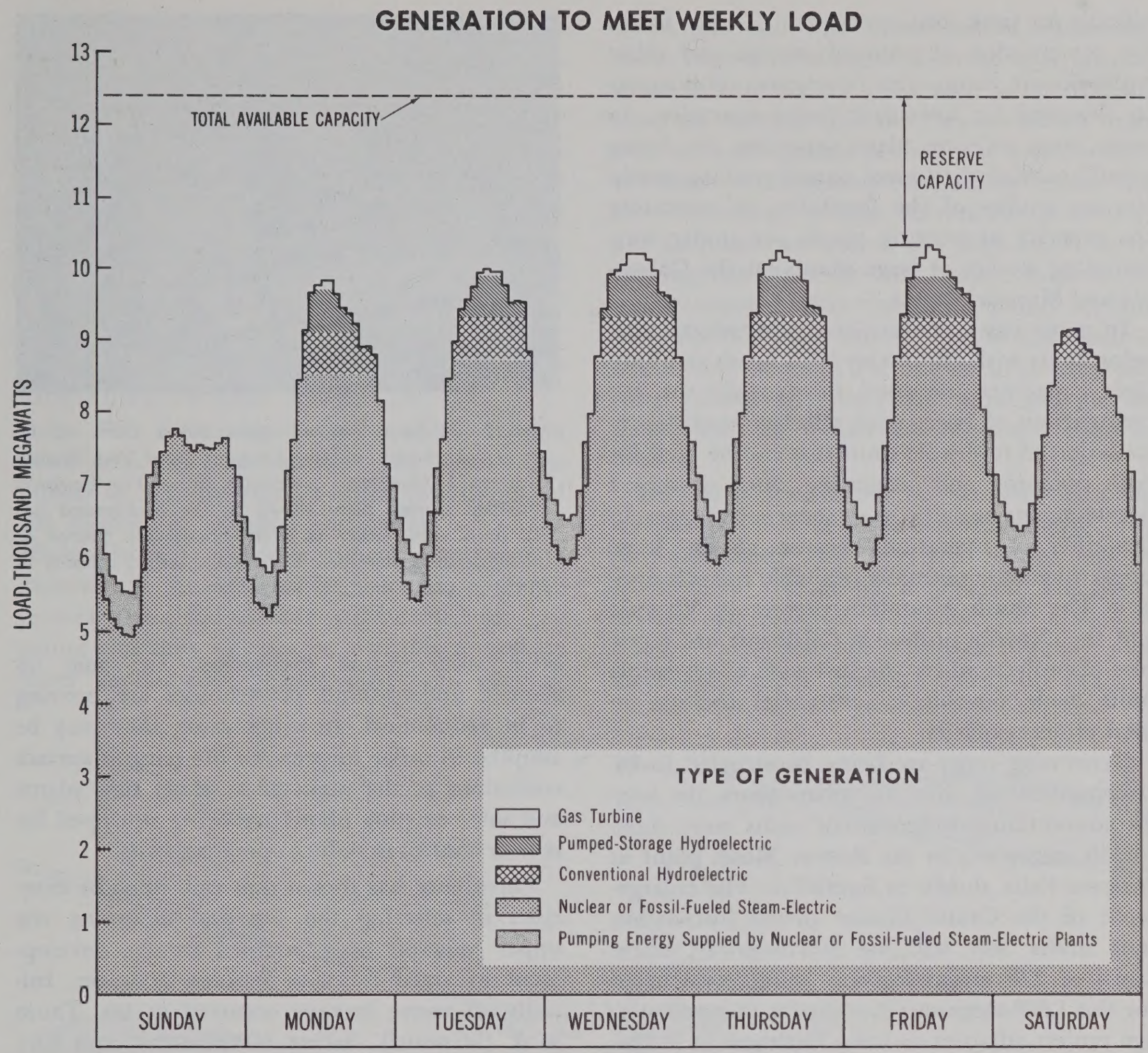


Figure 7.3

night to provide pumping energy. Because the time of the pumping cycle may be as much as 1½ times that of the generation cycle with units operating at full load, a daily pumping cycle of eight or nine hours would assure only about six hours of generation per day. This would be inadequate to serve the load shown on figure 7.3. Normally, therefore, it is necessary to construct reservoirs having adequate storage capacity to permit operation on a weekly cycle with substantial pumping over weekends, as depicted on figure 7.3 Reservoir storage capacities should be sufficiently large to assure dependable operation under most adverse load conditions. In most areas such conditions occur during summer peak periods when long and continuous periods of high temperatures are experienced. Under these criteria, with few exceptions, the reservoirs of pumped storage developments should have sufficient storage capacities to permit from 10 to 20 hours of continuous full load operation.

Trends in Development

The current trend toward construction of very large nuclear and fossil-fueled steam-electric units which operate best at high plant factors has increased the need for plants designed spe-

cifically for peak load operation. This has led to the construction of pumped storage and other hydroelectric plants with large generation capacity designed for low plant factor operation. In some cases, existing plant capacities are being greatly expanded to meet system peaking needs. Various studies of the feasibility of increasing the capacity of existing plants are under way, including studies of large plants on the Columbia and Missouri Rivers.

In many cases, conventional hydroelectric developments with reasonably high heads can have their capacities increased substantially by the construction of lower pool afterbays and the installation of reversible units that can be used for both pumping and generating. Such combined developments usually have some advantages in flexibility of operation because of the large upper reservoirs normally available in such projects. The Smith Mountain project in Virginia and the Oroville project in California are examples of projects where the inclusion of reversible units made possible a substantial increase in total project capacity.

Generating units are being constructed in increasingly larger sizes. For many years, the largest conventional hydroelectric units were those of 150 megawatts in the Robert Moses plant at Niagara Falls, shown in figure 7.4. The enlargement of the Grand Coulee power installation now under way will use 600-megawatt units. Units of 270 megawatts are being constructed for the 1,620-megawatt Ludington pumped storage project adjacent to Lake Michigan in Michigan and 382.5-megawatt units are scheduled for the 1,530-megawatt Raccoon Mountain pumped storage project on the Tennessee River in Tennessee. This trend to plants and units of larger sizes is likely to continue, with probable savings in both capital and operating costs.

For developing economically the power potential of sites with heads in the range of 15 to 35 feet, axial-flow turbines of the tubular type have been designed and are now being constructed. Also, bulb units of the type developed in Europe are being considered for installation at certain low-head plants in this country.

Improvements in the design and construction of dams are contributing to the economies of hydroelectric power developments. Also contributing to such economies are advances in the techniques and equipment used in tunneling and

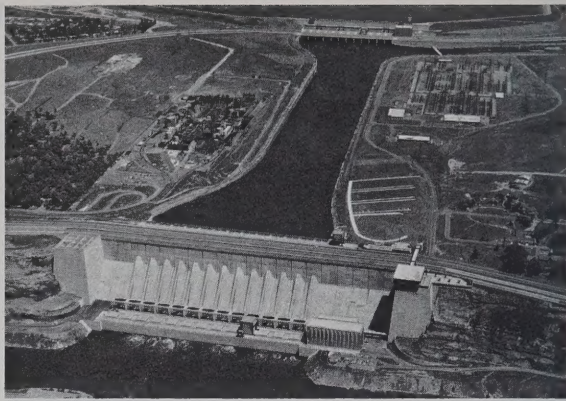


Figure 7.4—Robert Moses Niagara Power Plant of the Power Authority of the State of New York houses thirteen 150-megawatt generating units. The Lewiston Pumped storage plant shown in the background has 12 units used either as 37,500-horsepower pumps or 20-megawatt generators. The total installed capacity of the two plants is 2,194 megawatts.

other underground excavation. In some instances, underground powerhouses are proving to be economical. In other cases, they may be adopted in order to preserve the natural surface conditions at the plant sites. Many new plants and some existing plants are being equipped for remote control to reduce operating costs.

Experience has shown that care must be exercised in selecting the site and designing the upper reservoir of a pumped storage development to avoid excessive leakage of water. Initially, excessive leakage occurred at the Taum Sauk (Missouri), Salina (Oklahoma), and Kinzua (Pennsylvania) projects, necessitating various remedial measures. The experience gained at these projects and others under construction should prove helpful in providing better designs for future projects. A unique lining is being provided for the upper reservoir dike of the 1,620-megawatt Ludington project adjacent to Lake Michigan. Beginning from the surface and proceeding toward the foundation, there will be (1) a mastic seal coat, (2) two, three-inch layers of asphaltic concrete, (3) a two-inch asphaltic base course, (4) a drainage zone of 18 inches of crushed rock, (5) a two-inch layer of asphaltic concrete, (6) a two-inch layer of asphaltic sub-base, and (7) a 4½ foot thick layer of calcareous silty sand. Submersible pumps will be embedded in the crushed rock drainage zone and connected with a continuous 12-inch perfo-

rated pipe located in the lower portion of the drainage zone and running around the reservoir.

There is considerable flexibility in the design of pumped storage projects. An example is the licensed Kinzua pumped storage project which has two 198-megawatt reversible units and one 26-megawatt conventional unit. The Corps of Engineers' Allegheny Reservoir serves as the lower pool. One of the reversible units, through use of a divided draft tube, has been designed to discharge either into Allegheny Reservoir or into the river below the dam. A sketch of the Kinzua project is shown in figure 7.5.

An FPC license has been issued to Arizona Power Authority to construct the Montezuma project in Arizona with an initial installation of 505 megawatts. Original plans were to use the effluent from a sewage treatment plant serving Phoenix as the source of water. Since, under present plans, the effluent will be used for irrigation and thus will not be available to replace water lost during project operation, groundwater from wells will be used instead. Upper and lower reservoirs of equal capacity will be constructed to provide a gross head of about 1,660 feet. As initially planned, there would have been an underground powerhouse with five conventional 100-megawatt generating units and five, three-stage pumps. Reversible units were not proposed because of the high head. In reviewing the plans for this project, however, it was concluded that reversible pump turbine units could be used and that this would result in a reduction of about $14 million in construction costs. Accordingly, the plans now provide for the installation of four 126-megawatt reversible units.

Because of the relative newness and the physical complexities of large pumped storage projects, the effects they may have on the aquatic environment are not well understood. The power houses are designed with deeply submerged pump-turbine runners to reduce negative pressures which cause cavitation and injure fish. Ob-

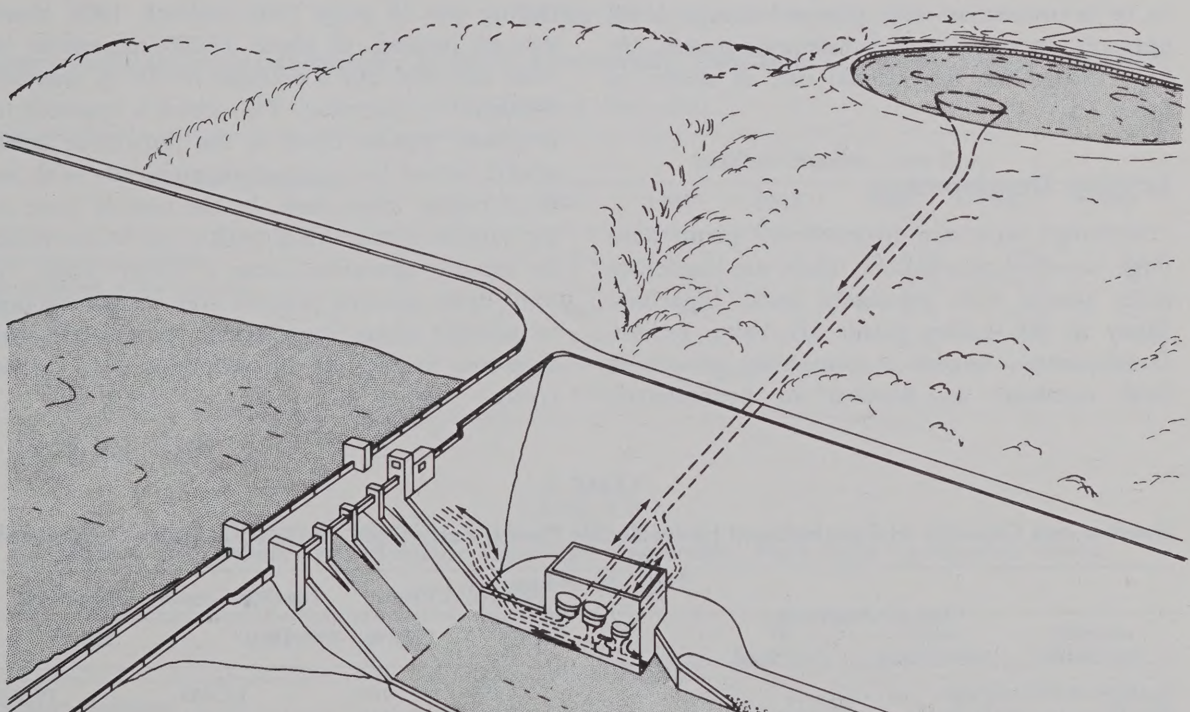


Figure 7.5—Sketch of Kinzua pumped storage project.

servations at some projects, although unconfirmed by quantitative studies, indicate that mortality rates generally are not significantly high for fish in the water passing through such units. The widely fluctuating reservoir surface elevations associated with pumped storage projects may adversely affect the spawning of warm water fish although some studies have shown that these species adapt to the fluctuations.

Trashracks and fish screens at pumped storage projects are regarded as self-cleaning because of the alternating direction of water flows through the units. Therefore, the design of fish protective facilities, when needed, is quite flexible. However, the location of fish screens and the velocities of water approaching them require particular attention. Additional studies are needed on the direct and indirect effects of pumped storage projects on the aquatic environment.

Because of the wide fluctuations in reservoir levels, many pumped storage projects are not suitable for recreational use. However, recreation facilities usually may be provided adjacent to, or in connection with, pumped storage developments. In some cases, sub-impoundments can be provided for recreational use, as shown in figure 7.6.

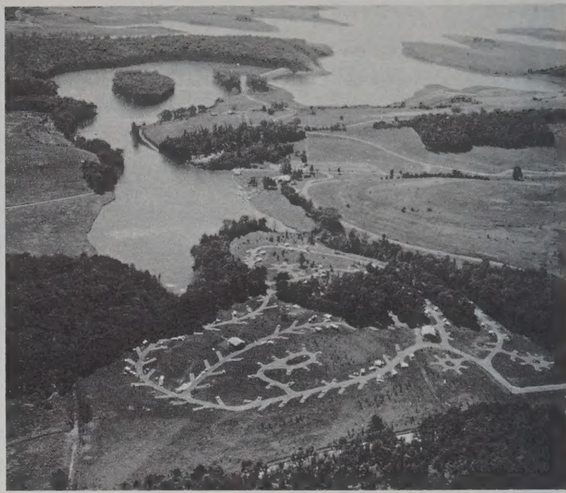


Figure 7.6—Philadelphia Electric Company's Muddy Run Recreation Park, developed as part of the pumped storage project, includes a constant level, 100-acre recreational lake in the upper power pool.

Existing Developments

Although most new hydroelectric plants have large capacity installations, there are numerous older plants with relatively small capacities. Many of the earlier plants are being retired. Consequently, despite a continuing growth in total capacity, the number of hydroelectric plants is decreasing. As may be noted in table 7.1 covering only conventional developments during the 10 years 1960 through 1969, there was an increase of about 18,000 megawatts in total capacity, but a decrease of 204 in number of plants in operation. This trend is expected to continue because many of the remaining small plants cannot be operated economically with today's higher labor costs. In the case of some of the smaller plants this situation can be corrected by remote operation from a larger plant. In some cases, existing projects may be redeveloped to provide larger installations, but usually the sites are inadequate or redevelopment is too costly.

TABLE 7.1

Number and Capacity of Conventional Hydroelectric Plants, Forty-Eight Contiguous States, 1960–1969

Class of Ownership	Number of Plants		Installed Capacity—Megawatts	
	1960 [1]	1969 [2]	1960 [1]	1969 [2]
Investor-owned utilities	956	776	13,059	16,211
Non-federal public utilities	270	287	3,924	11,697
Federal	114	144	14,201	21,556
Industrial	345	274	729	688
Total	1,685	1,481	31,913	50,152

[1] January 1.
[2] December 31.

Trends in Ownership

The growth in conventional hydroelectric capacity from 1920 to 1970 by categories of ownership is illustrated in table 7.2.

Investor-owned utilities accounted for most of the earlier hydroelectric developments. By the end of 1970, however, Federally owned hydroelectric capacity constituted about 44 percent of the total. The Federal agencies which operate hydroelectric capacity are listed in table 7.3, together with the total capacity in operation, under construction, and authorized.

The total pumped storage capacity in operation on December 31, 1970, amounted to 3,689 megawatts. Investor-owned utilities accounted for 65 percent of the total capacity, non-federal public utilities accounted for 21 percent, and the remaining 14 percent was Federally owned.

Projects Existing and Under Construction

At the end of 1970, about 46 percent of the 52,300 megawatts of conventional hydroelectric capacity in the United States was in the Pacific Coast States of Washington, Oregon, and California; about 33 percent of the total was in the Columbia River Basin. The locations of principal projects in the Columbia River Basin are shown in figure 7.7.

At the Grand Coulee project, a third power plant is being constructed on the right bank of the Columbia River immediately downstream from the dam, as illustrated in figure 7.8. This plant is planned for twelve 600-megawatt units, although only six units are currently authorized and now under construction. Completion of the authorized units and the scheduled increase in capacity of existing units will bring the total installation at the project to 5,870 megawatts. Also, the Grand Coulee pumping plant which pumps irrigation water from the reservoir is scheduled to have six 50-megawatt pumping-generating units, of which two are now under construction. Completion of the remaining pumping-generating units and the six additional units

TABLE 7.2

Conventional Hydroelectric Capacity by Class of Ownership, Forty-Eight Contiguous States, 1920–1970

[Thousands of Megawatts]

Class of Ownership	Installed Capacity: Year End					
	1920	1930	1940	1950	1960	1970
Investor-owned utilities	3.5	7.7	8.5	9.7	13.4	16.6
Non-federal public utilities	0.2	0.7	1.1	1.5	4.4	12.1
Federal	*0.0	0.2	1.7	6.5	14.6	22.9
Industrial	1.1	1.1	1.1	1.0	0.7	0.7
Total, all plants	4.8	9.7	12.4	18.7	33.1	52.3

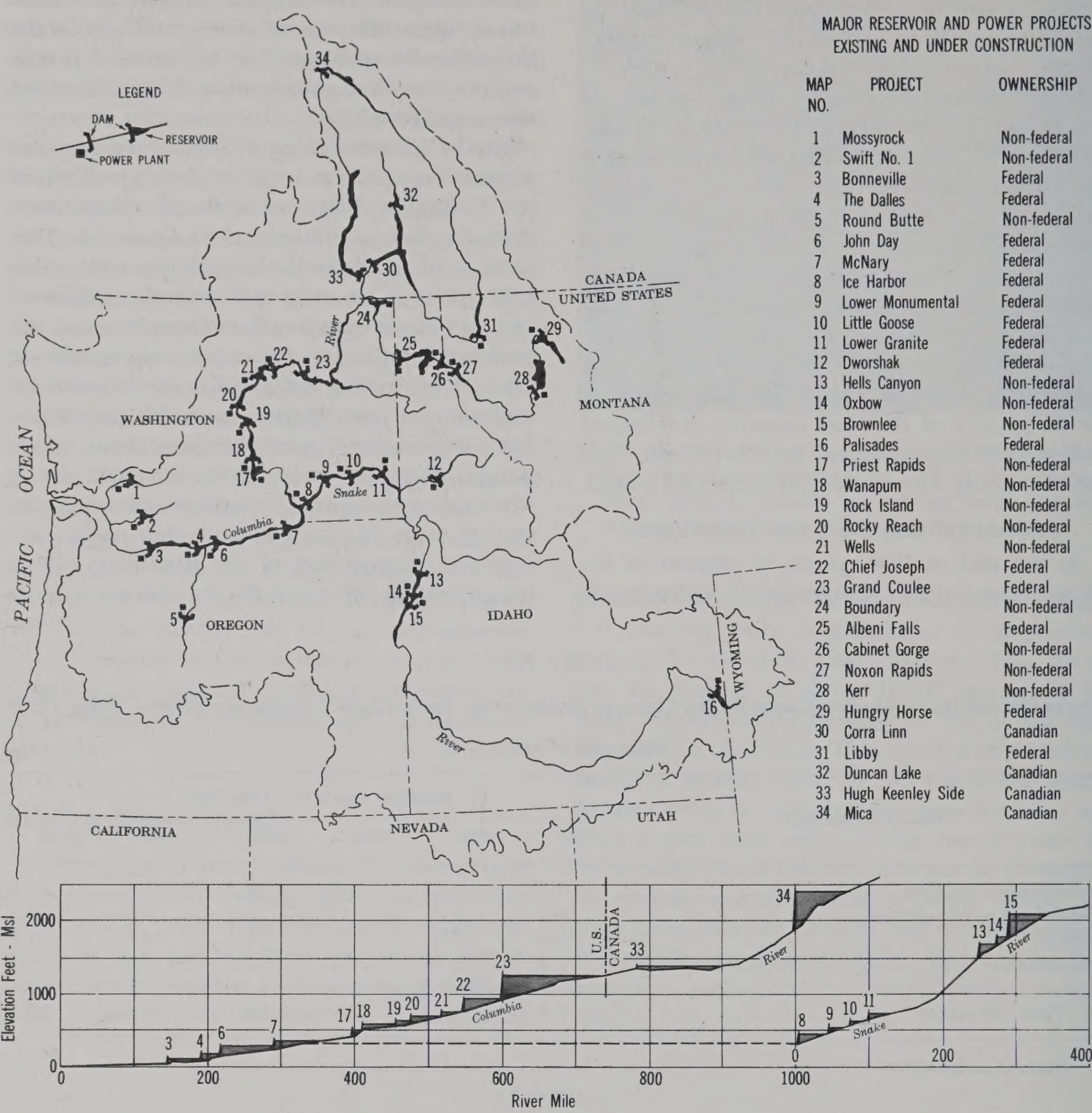
*Less than 50 MW.

TABLE 7.3

Federal Conventional Hydroelectric Capacity—Megawatts, Forty-Eight Contiguous States, December 31, 1970

Federal Agency	In Operation	Under Construction	Ultimate Authorized
Corps of Engineers	12,578	3,513	24,290
Bureau of Reclamation	7,230	4,008	11,707
Tennessee Valley Authority	3,083	45	3,128
International Boundary and Water Commission	31		122
Bureau of Indian Affairs	14		14
National Park Service	3		3
Total	22,939	7,566	39,264

MAP AND PROFILE OF COLUMBIA RIVER BASIN



MAJOR RESERVOIR AND POWER PROJECTS EXISTING AND UNDER CONSTRUCTION

MAP NO.	PROJECT	OWNERSHIP
1	Mossyrock	Non-federal
2	Swift No. 1	Non-federal
3	Bonneville	Federal
4	The Dalles	Federal
5	Round Butte	Non-federal
6	John Day	Federal
7	McNary	Federal
8	Ice Harbor	Federal
9	Lower Monumental	Federal
10	Little Goose	Federal
11	Lower Granite	Federal
12	Dworshak	Federal
13	Hells Canyon	Non-federal
14	Oxbow	Non-federal
15	Brownlee	Non-federal
16	Palisades	Federal
17	Priest Rapids	Non-federal
18	Wanapum	Non-federal
19	Rock Island	Non-federal
20	Rocky Reach	Non-federal
21	Wells	Non-federal
22	Chief Joseph	Federal
23	Grand Coulee	Federal
24	Boundary	Non-federal
25	Albeni Falls	Federal
26	Cabinet Gorge	Non-federal
27	Noxon Rapids	Non-federal
28	Kerr	Non-federal
29	Hungry Horse	Federal
30	Corra Linn	Canadian
31	Libby	Federal
32	Duncan Lake	Canadian
33	Hugh Keenley Side	Canadian
34	Mica	Canadian

Figure 7.7

planned for the third powerhouse would bring the total capacity at the Grand Coulee complex to 9,770 megawatts, making it the largest hydroelectric development in the world.

Figure 7.9 shows the locations of the 130 conventional hydroelectric power projects developed and under construction, having capacities of 100 megawatts or more. These projects are listed by regions in table 7.4.

During the past decade there has been a sharp increase in interest in pumped storage projects. The Rocky River plant in Connecticut, the first pumped storage plant, was placed in operation in 1929. By the end of 1966 a total of only nine plants were operating, with an aggregate capacity of about 1,500 megawatts. During the next four years, 22 new plants, with a capacity of about 11,000 megawatts, were completed or under construction. At the end of 1970, total

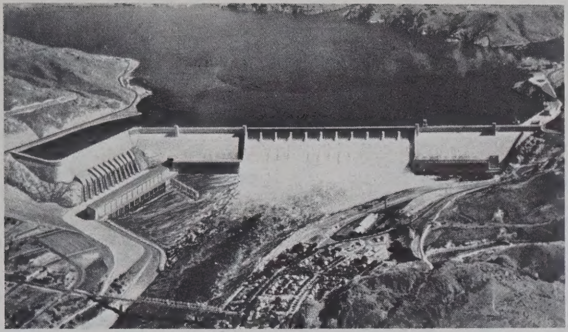


Figure 7.8—Grand Coulee Dam with artist's conception of the new third power plant which will house twelve 600-megawatt generating units.

pumped storage generating capacity amounted to 3,689 megawatts.

Pumped storage projects in operation and under construction on December 31, 1970, are listed in table 7.5 and their locations are shown on figure 7.14.

Developments Under FPC Licenses

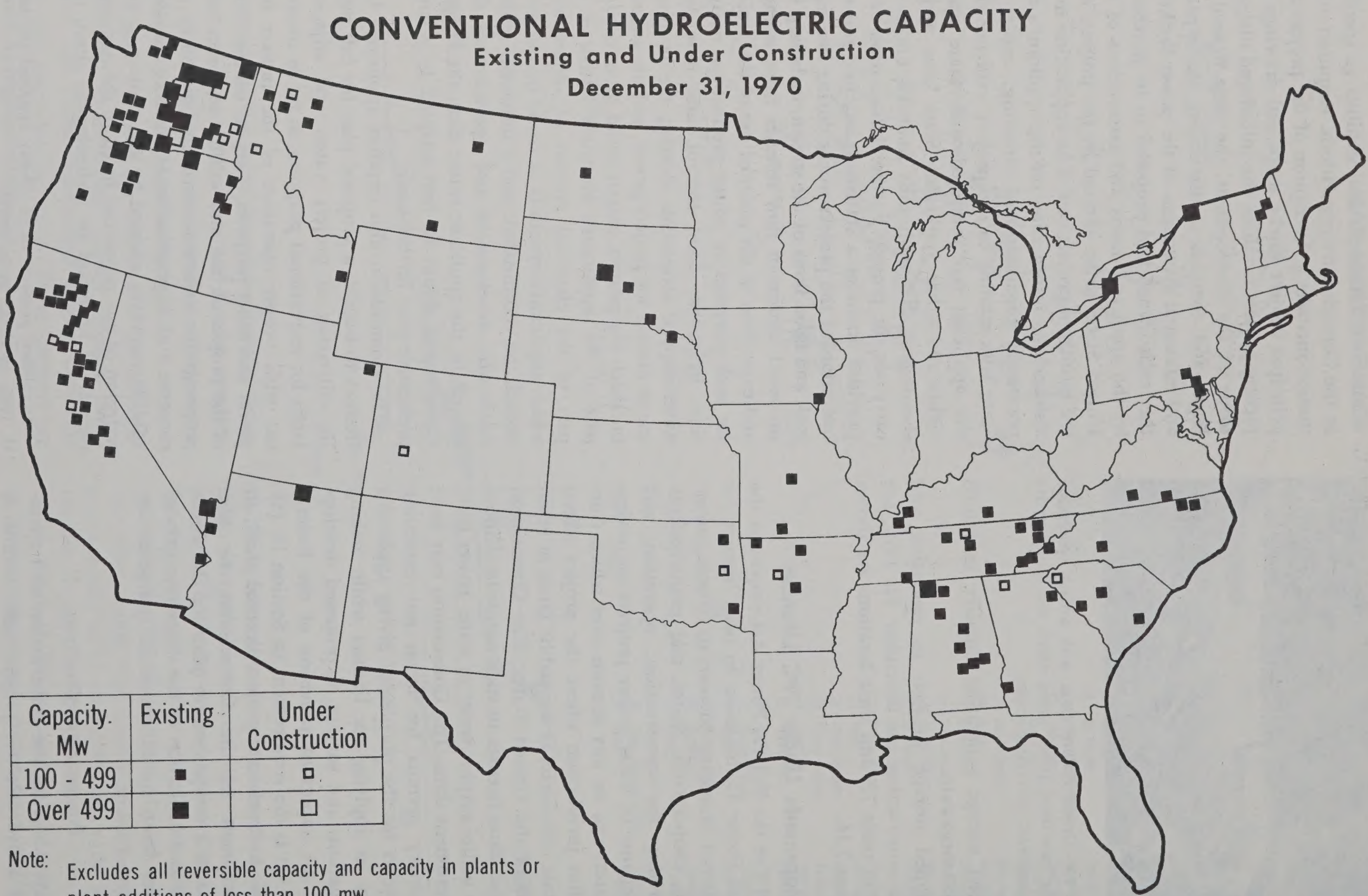
Part I of the Federal Power Act empowers the Federal Power Commission to issue licenses for periods not exceeding 50 years to citizens, corporations, cooperatives, States, and municipalities authorizing the construction, operation, and maintenance of water power projects on navigable waterways, on any streams over which Congress has jurisdiction where the project affects interstate commerce, or on public lands or reservations of the United States. The Commission may also issue licenses to such non-federal interests to utilize surplus water or water power from a Government dam. The Commission may issue preliminary permits for terms not exceeding three years for the purpose of giving applicants priority in applying for licenses while making examinations and surveys of proposed developments. An important provision of the Federal Power Act is the requirement in Section 10 (a) that any hydroelectric project licensed shall, in the judgment of the Commission, be best adapted to a comprehensive plan for the development and utilization of the water resources of the river basin for all beneficial purposes, including recreation.

Processing Applications

An applicant for the construction and operation of a hydroelectric project must furnish a number of statements and exhibits as specified in the Commission's regulations. Required information includes a description of the project and principal project works, maps and drawings depicting project facilities, the initial and ultimate scope of the development, the time desired to begin and complete construction, the capacity and estimated generation of the power facilities, the lands owned and proposed to be purchased by the applicant, lands and reservations of the United States to be affected by the project, and the estimated project cost. The application must also include information on the applicant's corporate or organizational structure, copies of State laws relating to the project, evidence that the applicant has complied with State water rights and other applicable State laws, and a showing of the applicant's financial ability to carry out the project. Further information to be provided includes a statement of the proposed operation of the project works during low, normal, and flood flows of the stream, including the proposed minimum flow releases from storage; and exposition of the planned use of the project for such purposes as power production, navigation, irrigation, flood control, and municipal water supply; statements showing the proposed use or market for project power, and the manner in which the project output could be utilized as part of the applicant's electrical system or as part of the electrical systems of others with which applicant's system is or could be interconnected and coordinated; and a statement setting forth why development and operation of the project by the applicant rather than the Federal Government would be best adapted to a comprehensive plan for the basin.

The Commission also requires applicants for licenses to furnish a proposed plan for full public utilization of project waters and adjacent lands for recreational purposes, so far as consistent with proper operation of the project for power and other purposes; a report on the effect of the project on fish and wildlife resources and proposals for measures considered necessary to conserve and, if practicable, to enhance fish and wildlife resources affected by the project; a description of any properties listed in the national register of historical or archeological sites[2], or

[2] Established pursuant to PL 89–665, approved October 15, 1966, 16 U.S.C. §470a (1970).



Note: Excludes all reversible capacity and capacity in plants or plant additions of less than 100 mw.

Figure 7.9

TABLE 7.4

Conventional Hydroelectric Capacity Existing and Under Construction as of December 31, 1970

[Listed Projects Have Installations of 100 MW or More]

Plant Name and Location	River	Owner	Installed Capacity, MW	
			Existing	Under Construction
NORTHEAST REGION				
Moore, N.H.	Connecticut	New England Power Co	140	
Comerford, N.H.	Connecticut	New England Power Co	140	
Robert Moses, N.Y.	St. Lawrence	Power Auth. of State of New York	912	
Niagara, N.Y.	Niagara	Power Auth. of State of New York	1,954	
Holtwood, Pa.	Susquehanna	Pa. Power and Light Co	107	
Safe Harbor, Pa.	Susquehanna	Safe Harbor Water Power Corp	227	
Conowingo, Md.	Susquehanna	Susquehanna Power and Phila. Elec. Pwr.	475	
Subtotal			3,955	
Installations of less than 100 MW			1,905	
Total			5,860	
EAST CENTRAL REGION				
Smith Mountain, Va.*	Roanoke	Appalachian Power Co	300	
Installations of less than 100 MW			718	61
Total			1,018	61
SOUTHEAST REGION				
Roanoke Rapids, N.C.	Roanoke	Virginia Electric and Power Co	100	
Gaston, N.C.	Roanoke	Virginia Electric and Power Co	178	
John H. Kerr, Va.	Roanoke	Corps of Engineers	204	
Cowans Ford, N.C.	Catawba	Duke Power Co	350	
Saluda, S.C.	Saluda	South Carolina Electric and Gas Co.	130	79
Pinopolis, S.C.	Santee-Cooper	South Carolina Public Serv. Authority	133	
Clark Hill, S.C.	Savannah	Corps of Engineers	280	
Keowee, S.C.	Keowee	Duke Power Co		140
Walters, N.C.	Pigeon	Carolina Power and Light Co	108	
Kentucky, Ky.	Tennessee	Tennessee Valley Authority	170	
Pickwick Landing, Tenn.	Tennessee	Tennessee Valley Authority	216	
Wilson, Tenn.	Tennessee	Tennessee Valley Authority	630	
Wheeler, Tenn.	Tennessee	Tennessee Valley Authority	356	
Chickamauga, Tenn.	Tennessee	Tennessee Valley Authority	108	
Watts Bar, Tenn.	Tennessee	Tennessee Valley Authority	150	
Norris, Tenn.	Clinch	Tennessee Valley Authority	101	
Calderwood, Tenn.	Little Tennessee	Tapoco, Inc	122	
Cheoah, N.C.	Little Tennessee	Tapoco, Inc	110	
Fontana, N.C.	Little Tennessee	Tennessee Valley Authority	225	
Fort Loudoun, Tenn.	Tennessee	Tennessee Valley Authority	131	
Douglas, Tenn.	French Broad	Tennessee Valley Authority	112	
Cherokee, Tenn.	Holston	Tennessee Valley Authority	120	
Barkley, Ky.	Cumberland	Corps of Engineers	130	
Old Hickory, Tenn.	Cumberland	Corps of Engineers	100	
Center Hill, Tenn.	Caney Fork	Corps of Engineers	135	
Cordell Hull, Tenn.	Cumberland	Corps of Engineers		100
Wolf Creek, Ky.	Cumberland	Corps of Engineers	270	
Hartwell, Ga.	Savannah	Corps of Engineers	264	
Walter F. George, Ga.	Chattahoochee	Corps of Engineers	130	
Carters, Ga.*	Coosawattee	Corps of Engineers		250
Lewis Smith, Ala.	Black Warrior	Alabama Power Co	158	

TABLE 7.4—Continued

Plant Name and Location	River	Owner	Installed Capacity, MW	
			Existing	Under Construction
SOUTHEAST REGION—Continued				
Martin, Ala	Tallapoosa	Alabama Power Co	154	....
Walter Bouldin, Ala	Coosa	Alabama Power Co	225	....
Jordan, Ala	Coosa	Alabama Power Co	100	....
Logan Martin, Ala	Coosa	Alabama Power Co	128	....
Lay Dam, Ala	Coosa	Alabama Power Co	177	....
Subtotal			6,005	569
Installations of less than 100 MW			3,234	186
Total			9,239	755
WEST CENTRAL REGION				
Fort Peck, Mont	Missouri	Corps of Engineers	165	....
Garrison, N. Dak	Missouri	Corps of Engineers	400	....
Oahe, S. Dak	Missouri	Corps of Engineers	595	....
Big Bend, S. Dak	Missouri	Corps of Engineers	468	....
Fort Randall, S. Dak	Missouri	Corps of Engineers	320	....
Gavins Point, Nebr	Missouri	Corps of Engineers	100	....
Keokuk, Iowa	Mississippi	Union Electric Co	125	....
Osage (Bagnell), Mo	Osage	Union Electric Co	172	....
Subtotal			2,345	....
Installations of less than 100 MW			867	27
Total			3,212	27
SOUTH CENTRAL REGION				
Dardanelle, Ark	Arkansas	Corps of Engineers	124	....
Ozark, Ark	Arkansas	Corps of Engineers		100
Robert S. Kerr, Okla	Arkansas	Corps of Engineers		110
Beaver, Ark	White	Corps of Engineers	112	....
Bull Shoals, Ark	White	Corps of Engineers	340	....
Table Rock, Mo	White	Corps of Engineers	200	....
Broken Bow, Okla	Mountain Fork	Corps of Engineers	100	....
Markham Ferry, Okla	Grand	Grand River Dam Authority	108	....
Subtotal			984	210
Installations of less than 100 MW			1,196	145
Total			2,180	355
WEST REGION				
Trinity, Cal	Trinity	Bureau of Reclamation	106	....
Judge Francis Carr, Cal	Clear Creek	Bureau of Reclamation	141	....
Folsom, Cal	American	Bureau of Reclamation	186	12
Auburn, Cal	N. Fk. American	Bureau of Reclamation		300
White Rock, Cal	S. Fk. American	Sacramento Municipal Utility Dist	190	....
Camino, Cal	S. Fk. American	Sacramento Municipal Utility Dist	142	....
Middle Fork American, Cal	M. Fk. American	Placer County Water Agency	110	....
Jaybird, Cal	Silver Creek	Sacramento Municipal Utility Dist	133	....
New Colgate, Cal	N. Yuba	Yuba County Water Agency	284	....
Edward Hyatt, Cal.*	Feather	California Dept. of Water Resources	351	....
Poe, Cal	N. Fk. Feather	Pacific Gas and Electric Co	124	....
Rock Creek, Cal	N. Fk. Feather	Pacific Gas and Electric Co	113	....
Belden, Cal	N. Fk. Feather	Pacific Gas and Electric Co	118	....
Caribou No. 2, Cal	N. Fk. Feather	Pacific Gas and Electric Co	110	....
Spring Creek, Cal	Spring Creek	Bureau of Reclamation	150	....

Plant Name and Location	River	Owner	Installed Capacity, MW	
			Existing	Under Construction
		WEST REGION—Continued		
Shasta, Cal	Sacramento	Bureau of Reclamation	420	
Pit No. 5, Cal	Pit	Pacific Gas and Electric Co	134	
Pit No. 7, Cal	Pit	Pacific Gas and Electric Co	104	
James B. Black, Cal	Pit	Pacific Gas and Electric Co	155	
New Melones, Cal	Stanislaus	Corps of Engineers		300
D. R. Holm, Cal	Cherry Creek	San Francisco Utilities Commission	135	
New Don Pedro, Cal	Tuolumne	Turlock Modesto Irrigation District	137	
Haas, Cal	N. Fk. Kings	Pacific Gas and Electric Co	135	
Big Creek No. 3, Cal	San Joaquin	Southern California Edison Co	107	
Mammoth Pool, Cal	San Joaquin	Southern California Edison Co	129	
Parker, Cal	Colorado	Bureau of Reclamation	120	
Davis, Ariz	Colorado	Bureau of Reclamation	225	
Glen Canyon, Ariz	Colorado	Bureau of Reclamation	950	
Hoover, Ariz.-Nev	Colorado	Bureau of Reclamation	1,340	
Morrow Point, Colo	Gunnison	Bureau of Reclamation	60	60
Yellowtail, Mont	Bighorn	Bureau of Reclamation	250	
Kerr, Mont	Flathead	Montana Power Co	168	
Hungry Horse, Mont	S. Fk. Flathead	Bureau of Reclamation	285	
Libby, Mont	Kootenai	Corps of Engineers		420
Hells Canyon, Oreg	Snake	Idaho Power Co	392	
Oxbow, Oreg	Snake	Idaho Power Co	190	
Brownlee, Idaho	Snake	Idaho Power Co	360	
Palisades, Idaho	Snake	Bureau of Reclamation	114	
Flaming Gorge, Utah	Green	Bureau of Reclamation	108	
Dworshak, Idaho	N. Fk. Clearwater	Corps of Engineers		400
Priest Rapids, Wash	Columbia	Grant County PUD No. 2	788	
Wanapum, Wash	Columbia	Grant County PUD No. 2	831	
Wells, Wash	Columbia	Douglas County PUD No. 2	774	
Chief Joseph, Wash	Columbia	Corps of Engineers	1,024	
Grand Coulee, Wash	Columbia	Bureau of Reclamation	[1] 2,066	3,600
Boundary, Wash	Pend Oreille	Seattle Dept. of Lighting	551	
Cabinet Gorge, Idaho	Clark Fork	Washington Water Power Co	200	
Noxon Rapids, Mont	Clark Fork	Washington Water Power Co	283	
Gorge, Wash	Skagit	Seattle Dept. of Lighting	134	
Diablo, Wash	Skagit	Seattle Dept. of Lighting	120	
Ross, Wash	Skagit	Seattle Dept. of Lighting	360	
Mayfield, Wash	Cowlitz	City of Tacoma	122	
Mossyrock, Wash	Cowlitz	City of Tacoma	300	
Rock Island, Wash	Columbia	Chelan County PUD No. 1	212	
Rocky Reach, Wash	Columbia	Chelan County PUD No. 1	712	502
John Day, Wash	Columbia	Corps of Engineers	1,890	270
The Dalles, Wash	Columbia	Corps of Engineers	1,119	688
Bonneville, Oreg	Columbia	Corps of Engineers	518	
McNary, Oreg	Columbia	Corps of Engineers	980	
Merwin, Wash	Lewis	Pacific Power and Light Co	135	
Yale, Wash	Lewis	Pacific Power and Light Co	108	
Swift No. 1, Wash	Lewis	Pacific Power and Light Co	204	
Pelton, Oreg	Deschutes	Portland General Electric Co	108	
Round Butte, Oreg	Deschutes	Portland General Electric Co	247	
Ice Harbor, Wash	Snake	Corps of Engineers	270	
Lower Monumental, Wash	Snake	Corps of Engineers	405	
Little Goose, Wash	Snake	Corps of Engineers	405	
Lower Granite, Wash	Snake	Corps of Engineers		405

TABLE 7.4—Continued

Plant Name and Location	River	Owner	Installed Capacity, MW	
			Existing	Under Construction
WEST REGION—Continued				
Detroit, Oreg.	N. Santiam	Corps of Engineers	100	...
Lookout Point, Oreg.	M. Fk. Willamette	Corps of Engineers	120	...
Subtotal			23,362	6,957
Installations of less than 100 MW			6,770	178
Total			30,132	7,135
Grand Total			[2] 51,641	8,333

*Denotes plant with reversible capacity in addition to the conventional capacity shown.

[1] Includes two 10-megawatt auxiliary units used to supply commercial power.

[2] Excludes industrial capacity which totals 682 megawatts.

eligible for listing in the national register, which might be affected by the project; a summary of the applicant's efforts to protect and enhance natural, historic, scenic, and recreational values in locating rights-of-way and transmission facilities; and a detailed statement of the environmental factors relating to the five points specified in the National Environmental Policy Act of 1969[3].

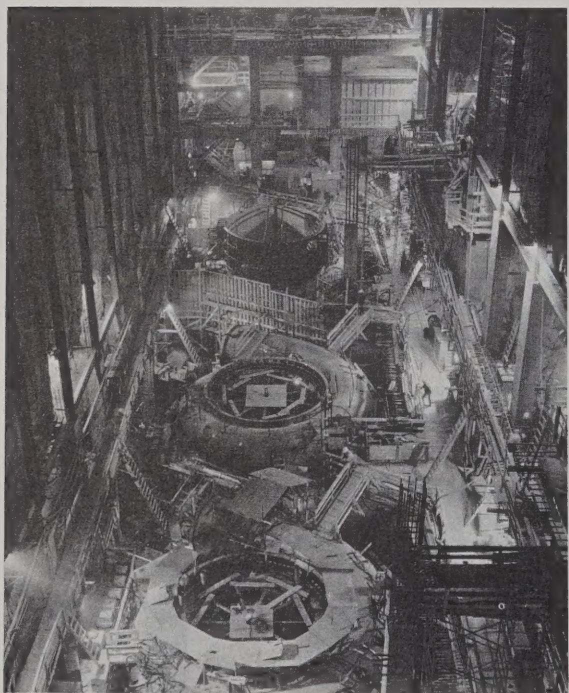


Figure 7.10—The Northfield Mountain pumped storage project in Massachusetts features an underground powerhouse with four reversible units. The 1,000-megawatt plant with a gross static head of 824 feet is expected to be in operation in 1972.

Pursuant to provisions of the Water Quality Improvement Act [3a], the Commission proposes to amend its rules to require applicants for hydroelectric project licenses to furnish certification from the appropriate State or Federal agency that project discharges to navigable waters of the United States would not violate applicable water quality standards, or else to outline steps taken in attempted compliance.

When an application for a license or license amendment is received, the Commission requests comments on the proposal, including the applicant's proposed environmental statement, from appropriate Federal and State agencies having interests and responsibilities for resource development and conservation. The Commission staff evaluates each proposed project for safety and adequacy, economic feasibility, and adaptability to a comprehensive plan of development. Frequently, hearings are held to ensure that a full record is available to the Commission on all relevant factors involved in the licensing action. Licenses issued by the Commision contain a number of standard construction and operating requirements and include a final environmental statement. These requirements are intended to

[3] PL 91–190, approved January 1, 1970, 42 U.S.C.A. §4321 et seq. (1971 supp.).

[3a] PL 91–224, approved April 3, 1970, 33 U.S.C.A. §1171 (1971).

TABLE 7.5

Pumped Storage Projects in the United States, December 31, 1970

Plant Name	State	Owner	Reversible Capacity, MW: In Operation	Reversible Capacity, MW: Under Construction
		NORTHEAST REGION		
Rocky River [1]	Conn	Conn. Lt. & Pwr. Co	[2] 7	
Lewiston	N.Y	Power Auth. of State of N.Y	240	
Yards Creek	N.J	Jersey Central P. & L. Co., Public Serv. E. & G. Co.	338	
Muddy Run	Pa	Philadelphia Elec. Co	800	
Kinzua	Pa	Pa. Elec. Co., Cleveland Elec. Illuminating Co.	422	
Northfield Mtn	Mass	The Conn. Lt. & Pwr. Co., The Hartford Elec. Lt. Co., Western Mass. Elec. Co.		1,000
Bear Swamp	Mass	New England Power Co		600
Blenheim-Gilboa	N.Y	Power Auth. of State of N.Y		1,000
		EAST CENTRAL REGION		
Smith Mountain [1]	Va	Appalachian Power Co	132	
Ludington	Mich	Consumers Pwr. Co., The Detroit Edison Co		1,620
		SOUTHEAST REGION		
Hiwassee [1]	N.C	Tennessee Valley Authority	60	
Raccoon Mountain	Tenn	Tennessee Valley Authority		1,530
Jocassee	S.C	Duke Power Co		305
Carters [1]	Ga	Corps of Engineers		250
		WEST CENTRAL REGION		
Taum Sauk	Mo	Union Elec Co	408	
Clarence Cannon [1]	Mo	Corps of Engineers		27
		SOUTH CENTRAL REGION		
Buchanan [1]	Tex	Lower Colo. River Authority	[2] 11	
Salina	Okla	Grand River Dam Authority	130	130
DeGray [1]	Ark	Corps of Engineers		28
Harry S. Truman	Mo	Corps of Engineers		160
		WEST REGION		
Castaic [1]	Calif	City of Los Angeles & State of California		400
Flatiron [1]	Colo	Bureau of Reclamation	9	
Senator Wash	Calif	Bureau of Reclamation	7	
Cabin Creek	Colo	Public Service Co. of Colo	300	
Edward Hyatt [1]	Calif	State of California	293	
Thermalito [1]	Calif	State of California	83	
San Luis	Calif	Bureau of Reclamation	[3] 424	
O'Neill	Calif	Bureau of Reclamation	25	
Grand Coulee Pumping Plant	Wash	Bureau of Reclamation		100
Horse Mesa [1]	Ariz	Salt River Project		100
Mormon Flat [1]	Ariz	Salt River Project		49
Total			3,689	7,299

[1] Plant also includes conventional hydroelectric units.
[2] A pump separate from the turbine is provided for pumping.
[3] Includes 222 MW allocated to State of California by contract.

assure optimum development of sites, conservation of resources, and preservation of the environment. Normally, each license also contains special conditions applicable to the particular project. Pursuant to existing statutes, the orders and actions of the Commission may be appealed to the courts. These safeguards may result in extensive delays in processing licensing applications.

Projects Under License

As of December 31, 1970, there were 580 constructed conventional hydroelectric plants operating under Federal Power Commission licenses within the 48 contiguous States. The 25,000 megawatts installed in these plants represented 48 percent of the total developed conventional hydroelectric capacity on that date. A total of 428 of the plants were owned by private utilities, 85 by non-federal public utilities, 7 by cooperatives, and 60 by industrial establishments. New conventional capacity under construction on December 31, 1970, would add 937 megawatts, making a total developed licensed capacity of about 26,000 megawatts. This new capacity consists of 580 megawatts being added at two plants already in operation and 357 megawatts of initial capacity at three new plants under construction.

Ten pumped storage projects with a total capacity of 3,146 megawatts were operating under FPC licenses on December 31, 1970, and 525 megawatts were operating at Federal projects not subject to licensing. An additional 4,655 megawatts were being constructed under license at five new plants and at one existing plant. Also, on the same date, license applications were pending for one existing project and one project under construction, providing a total capacity of 407 megawatts. Of the 10,988 megawatts of pumped storage capacity existing and under construction, more than 70 percent will operate under license.

In addition to the foregoing, 1,286 megawatts of new pumped storage capacity were authorized by four outstanding licenses but were not under active construction as of December 31, 1970[4]. Also, applications for license or preliminary permit were pending for 11 projects involving nearly 8,500 megawatts of new capacity. Still other projects were being actively considered. It appears, therefore, that actual installations of pumped storage capacity in 1980 will exceed the 19,000 megawatts which the 1964 National Power Survey projected.

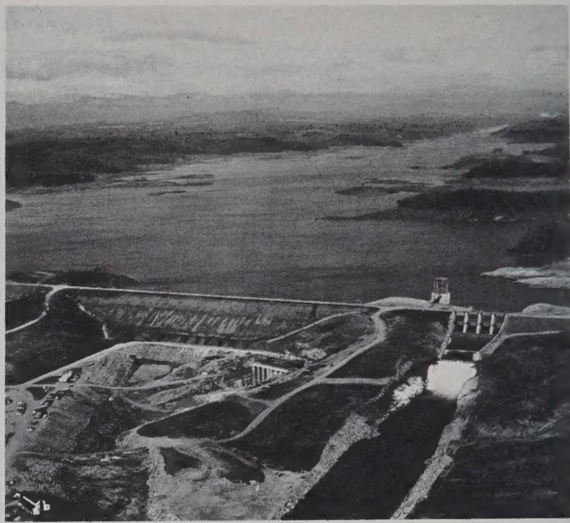


Figure 7.11—Duke Power Company's Keowee hydroelectric project with a generating capacity of 140 megawatts will serve as the lower pool for the Jocassee pumped storage development and furnish cooling water for the Oconee Nuclear plant expected to begin operation in 1971.

Since the construction and operation of dams and reservoirs may involve hazards to the public safety, the Commission provides for comprehensive inspection programs. Proposed project sites are inspected by the FPC staff during early planning stages to review the adequacy of an applicant's investigations and designs. Licensees for major new projects are required to engage a board of qualified engineering consultants to review initial designs and to monitor project construction. Licensees are also required to submit their programs of construction for FPC approval. Projects under construction are inspected monthly or more frequently by the Commission staff. Projects in operation are inspected annually by the FPC staff to assure that they are being maintained and operated efficiently and safely. The Commission's regulations require licensees to have operating projects inspected at least once every five years by qualified independent engineering consultants.

[4] Does not include the Cornwall project of 2,000 megawatts for which license was issued August 19, 1970, but is being contested in court.

The 1970 issue of the Commission's publication, *Recreation Opportunities at Hydroelectric Projects Licensed by the Federal Power Commission,* lists 5,830 outdoor recreational areas and facilities available to the general public at licensed projects. It describes recreational facilities at 555 reservoir-lakes with 22,000 miles of shoreline and a total water surface of 1.9 million acres. Among the available water recreation facilities are 2,264 boat ramps and 1,134 bathing areas. There are 1,349 picnic areas, and 971 camping areas on lands surrounding the reservoirs. Marinas, fishing piers, playgrounds and other facilities are provided at many projects, and hiking and riding trails are included in many developments.

Relicensing or Federal Takeover

The Federal Power Act provides that at the expiration of the prescribed license term, a hydroelectric project, if not publicly owned, may be taken over by the United States or relicensed to the original licensee or to another applicant. Under its regulations, as modified pursuant to a 1968 amendment to the Act, if the Commission determines that a project should be relicensed it will so order. However, if any Federal department or agency recommends takeover, the Commission will, upon motion of such department or agency, stay the effective date of its order for two years to permit presentation of the case for takeover to the Congress. If by the expiration of the two-year stay the Congress has not authorized takeover, the new license will become effective.

When the licensee does not wish to continue power operations and, in the judgment of the Commission, conversion of the project to nonpower use would best serve comprehensive development of the affected lands and waterways, the FPC is authorized to issue a license for that purpose. The nonpower license would be temporary, continuing only until such time as in the Commission's judgment a State, municipal, or interstate agency, or another Federal agency assumes regulatory supervision of the involved lands and facilities.

Development Under Comprehensive Basin Plans

The planning, construction, and operation of hydroelectric projects are increasingly affected by other water uses and needs. Recent studies demonstrate an increasing demand for water resource developments to provide municipal and industrial water supply, water quality control, and water-based recreation, in addition to the needs for power, flood control, navigation, and irrigation. These demands make it essential that individual water resources projects be considered as parts of long-range comprehensive plans of development. Thus, an important consideration in planning hydroelectric power projects is the harmonizing of the needs and demands of all appropriate water uses.

On some rivers, such as the Salmon River in Idaho, the preservation of anadromous fish is of particular significance. Research that would solve the fish-passage problems at high dams would facilitate early use of several favorable water power sites. The impoundments should not, however, flood vital spawning grounds. In water shortage areas, such as the Pacific Southwest, water needs for consumptive uses are of highest importance. Large-scale interbasin water diversion plans are being considered to assist in the supply of such needs. Some of these plans would include the development of hydroelectric power, and all would require large amounts of power for pumping water for municipal, industrial and agricultural purposes.

Federal-State Planning Activities

Federal, State, and local interests are becoming increasingly aware of the importance of planning for the comprehensive development and utilization of the Nation's water and related land resources. Most recent planning studies, and those now scheduled, provide for the cooperation of all interests. Despite the planning work that has been accomplished to date, a great deal of additional study is needed.

A major effort is under way by Federal and State agencies to prepare comprehensive plans of development and management for the principal river basins in the United States. The Water Resources Council [5] has the major responsibility for coordinating the Federal effort on the comprehensive river basin studies with respect to budgets, technical and policy guidelines, and review and submission of the completed reports

[5] Established by Public Law 89–80, approved July 22, 1965, 42 U.S.C. §1962a (1970).

to the President and the Congress. Members of the Council are the Secretaries of Agriculture; the Army; Health, Education and Welfare; the Interior; and Transportation (on matters pertaining to navigation features of water resource projects); and the Chairman of the Federal Power Commission. The Secretaries of Commerce and Housing and Urban Development and the Administrator of the Environmental Protection Agency are associate members of the Council. The comprehensive planning program being carried out under the direction of the Council includes 19 broad framework studies, of which 10 have recently been completed or will be completed in 1972. It also includes 15 more detailed regional or river basin studies, of which 12 are complete or will be completed in 1972.

The framework studies include projections of the availability of water and related land resources, furnish a general appraisal of development needs, and serve as a guide to further detailed planning. The river basin studies include the formulation and evaluation of projects which should be initiated in the next 10 to 15 years, with sufficient detail to permit Congressional consideration of those proposed for Federal development.

The Water Resources Council is also directed to maintain continuing study of the adequacy of water supplies in each water resource region of the country and of the relationship of comprehensive river basin or regional plans to the requirements of larger regions. These studies are to be reported from time to time in assessments of the adequacy of the Nation's water and related land resources. The first national assessment was published in 1968.

The Colorado River Basin Project Act [6] authorized the Secretary of the Interior to make reconnaissance-level studies to develop a general plan to meet the water requirements of the 11 Western States. The plan will also delineate alternative sources for augmenting the flows of the Colorado River. This Westwide study is being carried out by the Bureau of Reclamation with the cooperation of affected States and Federal agencies. Progress reports on the studies will be made every two years beginning in 1971; and the final report is due in 1977.

[6] Public Law 90-537, approved September 30, 1968, 43 U.S.C. § 1501 et seq. (1970).

A seven-member National Water Commission [7] is making a five-year study which will review present and anticipated national water resource problems, project future water requirements, and identify alternative ways of meeting the requirements—giving consideration, among other things, to conservation and more efficient use of existing supplies, increased usability by reduction of pollution, innovations to encourage the highest economic use of water, interbasin transfers, and technological advances including desalting, weather modification, and waste water purification and reuse. The Commission also will consider economic and social consequences of water resource development. The Federal water resource agencies, including the Federal Power Commission, are cooperating in the studies of the National Water Commission.

Water Resource Appraisals

The Commission needs up-to-date river basin studies to meet the requirement of Section 10(a) of the Federal Power Act that a project to be licensed or relicensed be best adapted to a comprehensive plan for use of the basin's resources. The work of other agencies is fully utilized to meet this requirement, but in many cases available studies are not current, do not provide sufficient information, or are not available in time to meet the Commission's needs. In such cases, river basin appraisal studies are made by the staff as the most effective means of obtaining the needed information.

The appraisal reports include a description of the basin and its economy, a summary of the findings of prior studies and the objectives of current investigations, a discussion of existing water and related land resources developments and the need for further development, and an analysis of plans for future basin development including the relationship thereto of existing and proposed hydroelectric projects.

Reports on 15 water resources appraisal studies had been completed by the end of 1970. The objective is to complete approximately six additional studies each year.

[7] Established by Public Law 90-515, approved September 26, 1968. See note to 42 U.S.C.A. § 1962a (1970)

Projected Developments

The Federal Power Commission staff maintains an inventory of undeveloped hydroelectric sites, based principally on river basin surveys and project investigations that have been made over the years. The studies encompass those by Federal agencies, various Federal-State entities, electric utilities, and others, including studies submitted with license applications. The estimates of undeveloped water power include projects for which studies have indicated both engineering and economic feasibility, as well as projects at sites where physical conditions suggest engineering feasibility but for which detailed studies of economic feasibility have not been made. The estimates are revised as additional information becomes available.

Hydroelectric Power Potential

The total conventional hydroelectric power potential of the 48 contiguous States at both developed and undeveloped sites that have been inventoried is estimated to be about 146,000 megawatts of capacity capable of producing an average of 530 million megawatt-hours of electric energy annually. The undeveloped portion of this total as of December 31, 1970, was about 94,000 megawatts and 274 million megawatt-hours.

Economics and other factors will preclude the development of many of the potential hydroelectric sites. Development of some sites may be prohibited by legislation. Examples of such legislation are the Colorado River Basin Project Act,[8] and the Wild and Scenic Rivers Act.[9] The former prohibits the Federal Power Commission from issuing licenses for projects on the Colorado River between the Glen Canyon and Hoover Dam projects. This reach of the Colorado River has an undeveloped power potential of about 3,500 megawatts. The latter Act prohibits the Commission from licensing the construction of any power facility affecting a river included in the national wild and scenic rivers system which was established by the Act. The 37 river reaches named in the Act to be included in that system or to be studied for possible inclusion in the system contain sites which could provide about 9,000 megawatts of hydroelectric capacity. The 37 river reaches named in the Act are shown on figure 7.12.

The availability of pumped storage sites is dependent primarily upon topography which permits development of a high head between two reservoirs in the same area. Little streamflow is required and the reservoirs can be small in comparison with storage reservoirs at conventional hydroelectric projects. In many areas of the country, therefore, there are virtually unlimited physical opportunities for developing pumped storage projects. Since only a limited number of sites have been investigated, the inventory of undeveloped pumped storage power is not as complete as that for undeveloped conventional hydroelectric power. However, using the studies of others and its own reconnaissance, the Commission staff has identified several hundred potential pumped storage sites capable of developing many thousands of megawatts of capacity.

Possible Future Projects

The cost of constructing a conventional hydroelectric project per kilowatt of installed capacity depends upon the type of project, its size and location, the head developed, the cost of lands required, and the cost of relocating facilities within or adjacent to the reservoir area, such as railroads, bridges, roads, buildings, and other improvements. Variations in costs are considerable but, on the average, investment costs per kilowatt are substantially higher than for thermal-electric plants or pumped storage projects. Operating expenses of conventional hydroelectric plants are much lower, however, principally because fuel is required to operate thermal-electric plants and electric energy is required for pumping at pumped storage projects. Consequently, as fuel costs increase, conventional hydroelectric power sites may become more favorable economically.

Cost data adequate for making economic analyses of most potential hydroelectric power sites are not available. Therefore, any projection of new conventional projects to be constructed during the period to 1990 is highly conjectural. Using available data and its own estimates of cost, the Federal Power Commission staff has made an appraisal of the undeveloped water power sites to select those which might be devel-

[8] Public Law 90–537, approved September 30, 1968, 43 U.S.C. § 1501 et seq. (1970).

[9] Public Law 90–542, approved October 2, 1968, 16 U.S.C. § 1271 et seq. (1970).

NATIONAL WILD AND SCENIC RIVERS SYSTEM

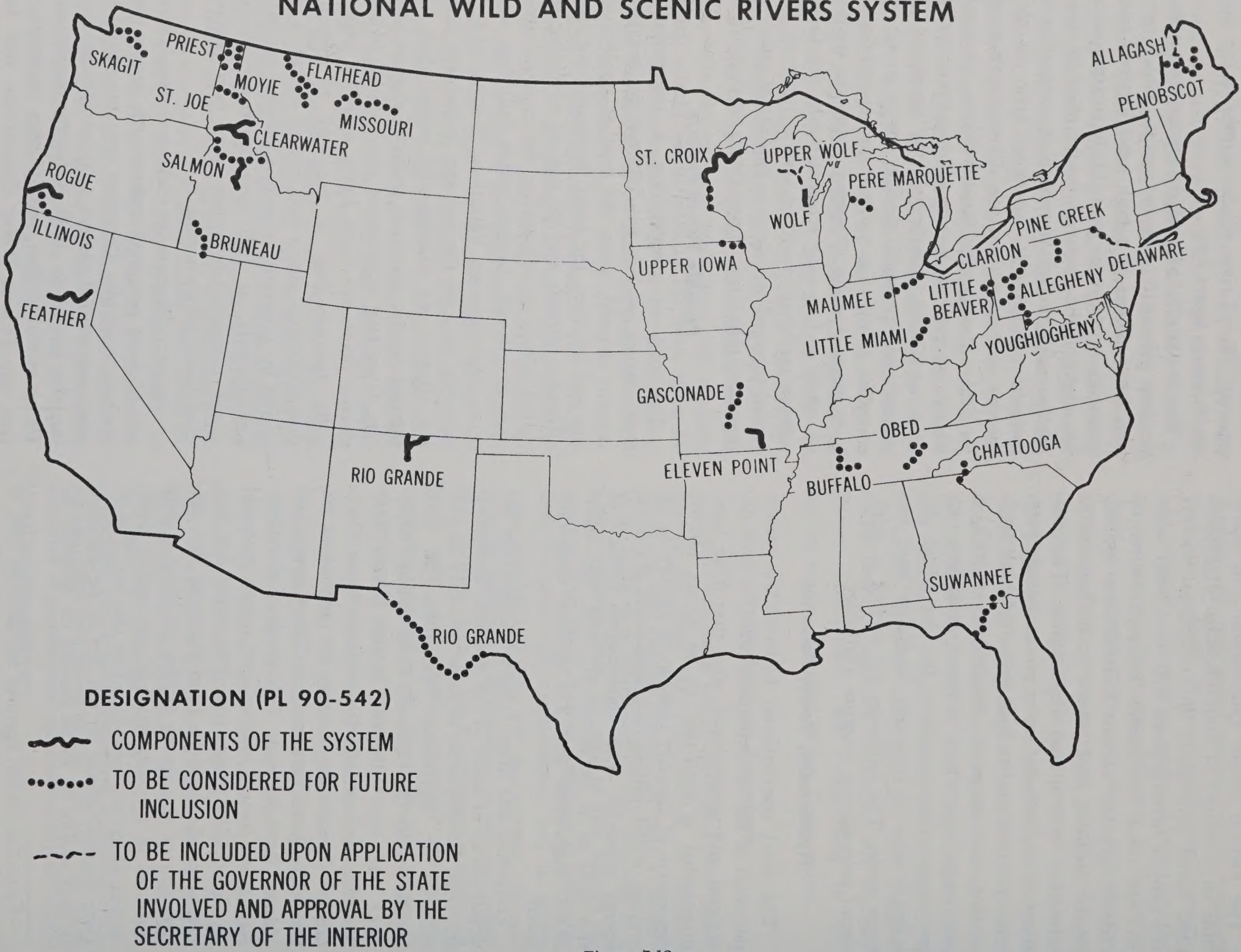


Figure 7.12

oped by 1990. It was recognized that any site considered for development would need to be adaptable to a comprehensive plan for the basin and compatible with the environment of the area. In examining the economics of potential projects which have already received Congressional authorization or have some licensing status, the annual charges used were those appropriate to the sponsoring entity. In screening other potential projects for which a sponsoring entity was not clearly identified, project economics were evaluated on the basis of Federal financing which results in lower project costs than non-federal financing. This was done to assure the inclusion of all projects that could be justified on that basis, but with full recognition that in many cases development might be accomplished by non-federal entities, including publicly and investor-owned utilities.

The staff appraisal included a review of the possibilities of adding capacity at existing projects. Many existing projects were constructed with provisions for additional future generating units, and these can be added at relatively low incremental costs. At other projects, such as Bonneville and Grand Coulee, it is necessary to construct a new powerhouse to provide additional generating capacity. In many cases, capacity additions become justified as load growth results in the need for additional peaking capacity.

Locations of projected new conventional projects and capacity additions having ratings of 100 megawatts or more are shown in figure 7.13. These projects and capacity additions are listed by regions in table 7.6. They would provide about 22,000 megawatts of new capacity and increase the total conventional hydroelectric capacity to about 82,000 megawatts by 1990. This total capacity would be capable of operating at an average annual plant factor of about 45 percent.

The magnitude and characteristics of the future loads in each region were examined to determine how much pumped storage capacity could be utilized by 1990. Specific potential pumped storage developments identified by reconnaissance studies, generally estimated to cost between $100 and $140 per kilowatt of installed capacity, were then tentatively selected for serving portions of the loads.

Locations of existing and projected new pumped storage projects are shown on figure 7.14. The new projects are listed by regions in table 7.7. The projects listed would provide about 59,000 megawatts of new capacity and increase the total pumped storage capacity to 70,000 megawatts by 1990. In listing these projects, it is recognized that in some regions there are numerous alternative sites available and that, for the sites selected, detailed engineering studies would be required to determine their economic feasibility in most cases. These studies would more carefully examine project construction costs and associated transmission costs, evaluate the energy losses in pumping and transmission, and compare the results with the costs of alternative types of facilities for providing peaking capacity available at the time decisions for such capacity additions must be made. Environmental and esthetic considerations would also be taken into account and might be determining factors in the selection of particular projects for construction.

Imports from Canada

Canada has a number of large conventional hydroelectric projects which are being developed as Canadian loads grow. Because of the rapid rate of growth in Canada, it appears that little hydroelectric power will be available on a long-term basis for use in the United States.

In eastern Canada, the Churchill Falls project in Labrador and other large projects in Quebec and New Brunswick are under construction. Although some of the output of these projects, possibly 300 to 350 megawatts, might be available for import on a short-term basis, it is anticipated that all of the power will be usable in Canada by about 1976. Quebec has large undeveloped hydroelectric resources along the rivers flowing into James Bay, Ungava Bay, and the north slope of the St. Lawrence. If this power were developed, it is possible that as much as 5,000 megawatts might be made available for export to the United States for an interim period, possibly 20 years.

In Manitoba, the first phase of major development of the Nelson River is under way with construction of the Kettle Rapids project. Power from this project will be delivered to Winnipeg over direct current transmission lines. The Nelson River, which flows from Lake Winnipeg to Hudson Bay, has the potential for development

TABLE 7.6

Possible New Conventional Hydroelectric Projects and Capacity Additions, Projected to 1990

[Listed Projects or Additions Would Have Installations of 100 MW or More]

Name of Project	River	State	Installed Capacity, MW	
			Capacity Addition	New Project
NORTHEAST REGION				
Harris	Kennebec	Maine	130	....
Dickey-Lincoln School	St. John	Maine		830
Holtwood	Susquehanna	Pa	162	....
Safe Harbor	Susquehanna	Pa	176	....
Clarion B* [1]	Clarion	Pa		180
Total			468	1,010
EAST CENTRAL REGION				
Beaver Hole	Cheat	W. Va		300
Devils Jumps	Big South Fk	Ky		500
Cumberland Falls	Cumberland	Ky		100
Lower Blue Ridge	New	Va		200
Bluestone	New	W. Va		180
Swiss*	Gauley	W. Va		400
Subtotal				1,680
Installations of less than 100 MW				77
Total				1,757
SOUTHEAST REGION				
Blairs	Broad	S.C		180
Greater Lockhart*	Broad	S.C		250
Trotters Shoals*	Savannah	S.C.-Ga		200
Sugar Creek	Elk	Ala		100
Celina	Cumberland	Ky		108
Anthony Shoals	Broad	Ga		100
Laurens Shoals*	Oconee	Ga		108
Upper Oconee*	Oconee	Ga		250
Thurlow	Tallapoosa	Ala	150	....
Martin	Tallapoosa	Ala	171	....
Emuckfaw	Tallapoosa	Ala		181
Crooked Creek	Tallapoosa	Ala		135
Subtotal			321	1,612
Installations of less than 100 MW			306	421
Total			627	2,033
WEST CENTRAL REGION				
Installations of less than 100 MW				69
SOUTH CENTRAL REGION				
Wolf Bayou	White	Ark		180
Sherwood* [2]	Mountain Fk	Okla		100
Gainesville	Red	Tex.-Okla		100
Denison	Red	Tex.-Okla	105	....
Upper Antlers	Kiamichi	Okla		100
Subtotal			105	480
Installations of less than 100 MW			153	80
Total			258	560

TABLE 7.6—Continued

Name of Project	River	State	Installed Capacity, MW	
			Capacity Addition	New Project
		WEST REGION		
Two Forks	S. Platte	Colo		138
Libby	Kootenai	Mont	420	
Kootenai Falls	Kootenai	Mont		360
Buffalo Rapids No. 2 [1]	Flathead	Mont		120
Buffalo Rapids No. 4 [1]	Flathead	Mont		120
Smoky Range [3]	N. Fk. Flathead	Mont		190
Spruce Park [3]	S. Fk. Flathead	Mont		120
Quartz Creek	Clark Fork	Mont		104
Hells Canyon	Snake	Oreg	130	
Brownlee	Snake	Idaho	180	
Lynn Crandall	Snake	Idaho		240
Garden Valley	S. Fk. Payette	Idaho		175
Lower Scriver	Scriver Creek	Idaho		120
Lenore	Clearwater	Idaho		200
Dworshak	N. Fk. Clearwater	Idaho	660	
Pyramid	W. Br. Cal. Aqueduct	Calif		158
Devil Canyon	E. Br. Cal. Aqueduct	Calif		117
Keno	Klamath	Oreg		100
Asotin	Snake	Idaho		540
Middle Snake	Snake	Idaho		2,415
Priest Rapids	Columbia	Wash	473	
Wanapum	Columbia	Wash	499	
Chief Joseph	Columbia	Wash	1,045	
Grand Coulee	Columbia	Wash	[4] 204	
Boundary	Pend Oreille	Wash	276	
Katka	Kootenai	Idaho		100
Ross	Skagit	Wash	169	
Diablo	Skagit	Wash	120	
Mossyrock	Cowlitz	Wash	150	
Rock Island	Columbia	Wash	231	
Ben Franklin	Columbia	Wash		848
John Day	Columbia	Wash	540	
Bonneville	Columbia	Oreg	324	
Yale	Lewis	Wash	108	
Muddy	Lewis	Wash		110
Ice Harbor	Snake	Wash	333	
Lower Monumental	Snake	Wash	405	
Little Goose	Snake	Wash	405	
Lower Granite	Snake	Wash	405	
Subtotal			7,077	6,275
Installations of less than 100 MW			355	1,361
Total			7,432	7,636
Grand Total			8,785	13,065

*Denotes plant that would have reversible capacity in addition to the conventional capacity shown.

[1] Alternative projects are being considered for this site.

[2] Project site is in a river reach designated in the State of Oklahoma's Scenic Rivers Act, approved March 17, 1970.

[3] Project site is in a river reach designated in PL 90–542 for study as possible addition to the National Wild and Scenic Rivers System.

[4] Capacity provided by increased ratings of existing units.

TABLE 7.7

Possible New Pumped Storage Capacity, Projected to 1990 as of December 31, 1970

[Listed Projects Have Installations of 300 MW or More]

Name of Project	River Basin	State	Gross Head, ft.	Usable Pondage, ac.-ft.	New Reversible Capacity, MW
NORTHEAST REGION					
Rowe	Kennebec	Maine	785	24,100	1,000
Canaan Mountain	Housatonic	Conn	900	41,000	[1] 2,000
Cornwall	Hudson	N.Y.	1,160	25,000	[2] 2,000
Schoharie Creek	Hudson	N.Y.	1,100	12,000	1,000
Middlesex #3	Oswego	N.Y.	1,203	16,500	1,700
Kittatinny Mountain	Delaware	N.J.	1,100	16,000	1,300
Enders No. 2 (Stony Creek)	Susquehanna	Pa.	975	19,800	1,950
Alfarata No. 3	Susquehanna	Pa.	1,302	10,800	1,200
Dutch Mtn. No. 3	Susquehanna	Pa.	1,300	18,000	2,200
Subtotal					14,350
Installations of less than 300 MW					370
Total					14,720
EAST CENTRAL REGION					
Davis	Cheat	W. Va	860	24,600	[3] 750
Chilo	Ohio	Ohio	440	9,250	350
Hart Falls	Ohio	Ind.-Ky	401	22,400	750
Booneville	Kentucky	Ky	591	10,450	500
Upper Blue Ridge	New	Va	262	290,000	[3] 1,600
Fayetteville No. 3	Kanawha	W. Va	1,039	19,200	1,700
Meadow Creek No. 1	Kanawha	W. Va	1,405	11,800	1,400
Swiss*	Kanawha	W. Va	700	33,000	1,600
Summersville	Kanawha	W. Va	370	14,400	550
Elkins No. 2	Monongahela	W. Va	1,460	7,200	900
Valley Point No. 1	Monongahela	W. Va	915	20,800	1,600
Whitcomb	Miami	Ind	299	19,100	500
Subtotal					12,200
Installations of less than 300 MW					150
Total					12,350
SOUTHEAST REGION					
Western Virginia		Va			1,500
Glendale Springs	New-Yadkin	N.C	1,160	31,000	1,100
Greater Lockhart*	Broad	S.C	170	([4])	750
Brushy Mountain	Broad	N.C	740	15,260	580
Frees	Broad	S.C	157	29,000	480
Green River	Broad	N.C	1,000	25,000	[5] 2,000
Trotters Shoals*	Savannah	S.C	145	([4])	400
Jocassee	Savannah	S.C	310	([4])	[6] 305
Bad Creek	Savannah	S.C	1,180	20,000	2,300
Brumley	Tennessee	Va	1,190	8,000	800
Subtotal					10,215
Installations of less than 300 MW					526
Total					10,741

TABLE 7.7—Continued

Name of Project	River Basin	State	Gross Head, ft.	Usable Pondage, ac.-ft.	New Reversible Capacity, MW
		WEST CENTRAL REGION			
Mississippi near Dakota	Upper Miss	Minn	714	14,450	900
Mississippi near Winona	Upper Miss	Minn	604	8,600	450
Oskar	Lake Superior	Mich	438	21,500	800
Port Wing	St. Louis	Wisc	448	37,100	1,400
Columbia Heights	Chippewa	Wisc	497	8,000	350
Subtotal					3,900
Installations of less than 300 MW					25
Total					3,925
		SOUTH CENTRAL REGION			
Magazine Mountain	Arkansas	Ark	2,150	8,530	1,000
Petit Jean	Arkansas	Ark	774	10,400	560
Spring Mountain	Arkansas	Ark	1,256	14,500	1,000
Mulladay	White	Ark	445	22,500	500
Marcella	White	Ark	950	11,000	700
Sherwood* [7]	Red	Okla	192	([4])	500
Tuskahoma [7]	Red	Okla	1,099	19,000	1,000
Boktukola	Red	Okla	400	60,000	1,000
Clayton	Red	Okla	990	8,400	500
Subtotal					6,760
Installations of less than 300 MW					[6] 260
Total					7,020
		WEST REGION			
Havasu Lake	Colorado	Ariz	1,020	25,000	[8] 1,000
Northern California		Calif			1,000
Central California		Calif			1,000
Castaic*	Santa Clara	Calif	1,048	10,000	[9] 800
Southern California No. 1		Calif			1,500
Southern California No. 2		Calif			1,500
Montezuma	Gila	Ariz	1,660	7,000	[10] 1,000
Blair Mountain	White	Colo	2,200	2,000	[5] 525
Antillon Lake	Chelan	Wash	1,290	25,900	1,000
Subtotal					9,325
Installations of less than 300 MW					717
Total					10,042
Grand Total					58,798

*Denotes plant that would have conventional capacity in addition to the reversible capacity shown.

[1] Preliminary permit issued July 26, 1971.

[2] License issued August 19, 1970, is being contested.

[3] Application for license is pending.

[4] Pondage would be available from a large mainstream reservoir.

[5] Application for preliminary permit is pending.

[6] Capacity addition at a licensed project.

[7] Project site is in a river reach designated in the State of Oklahoma's Scenic Rivers Act, approved March 17, 1970.

[8] Preliminary permit was issued November 18, 1970.

[9] Application for license is pending for this capacity plus 400 megawatts under construction.

[10] License has been issued for 505 megawatts, but construction has not started.

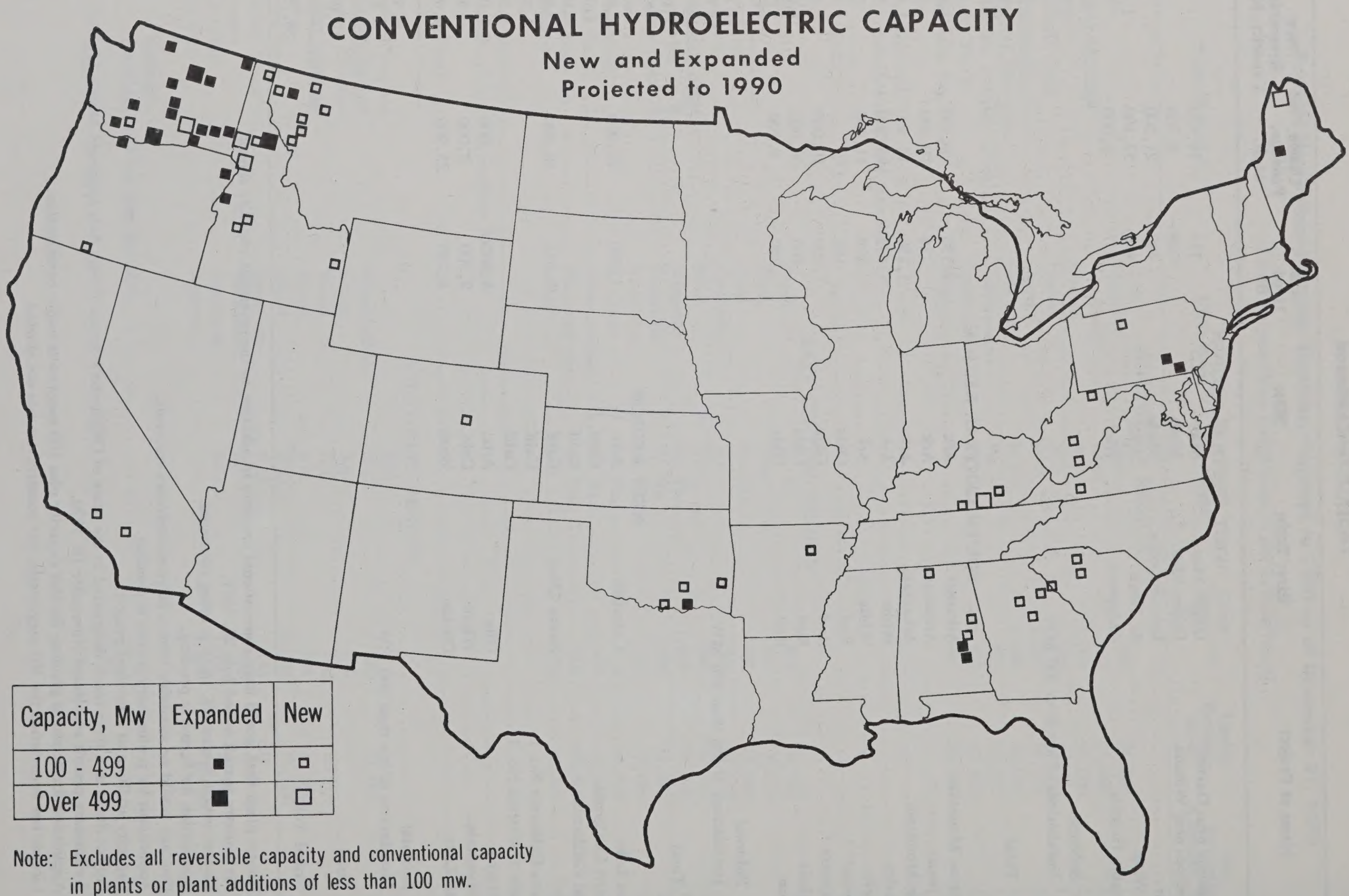
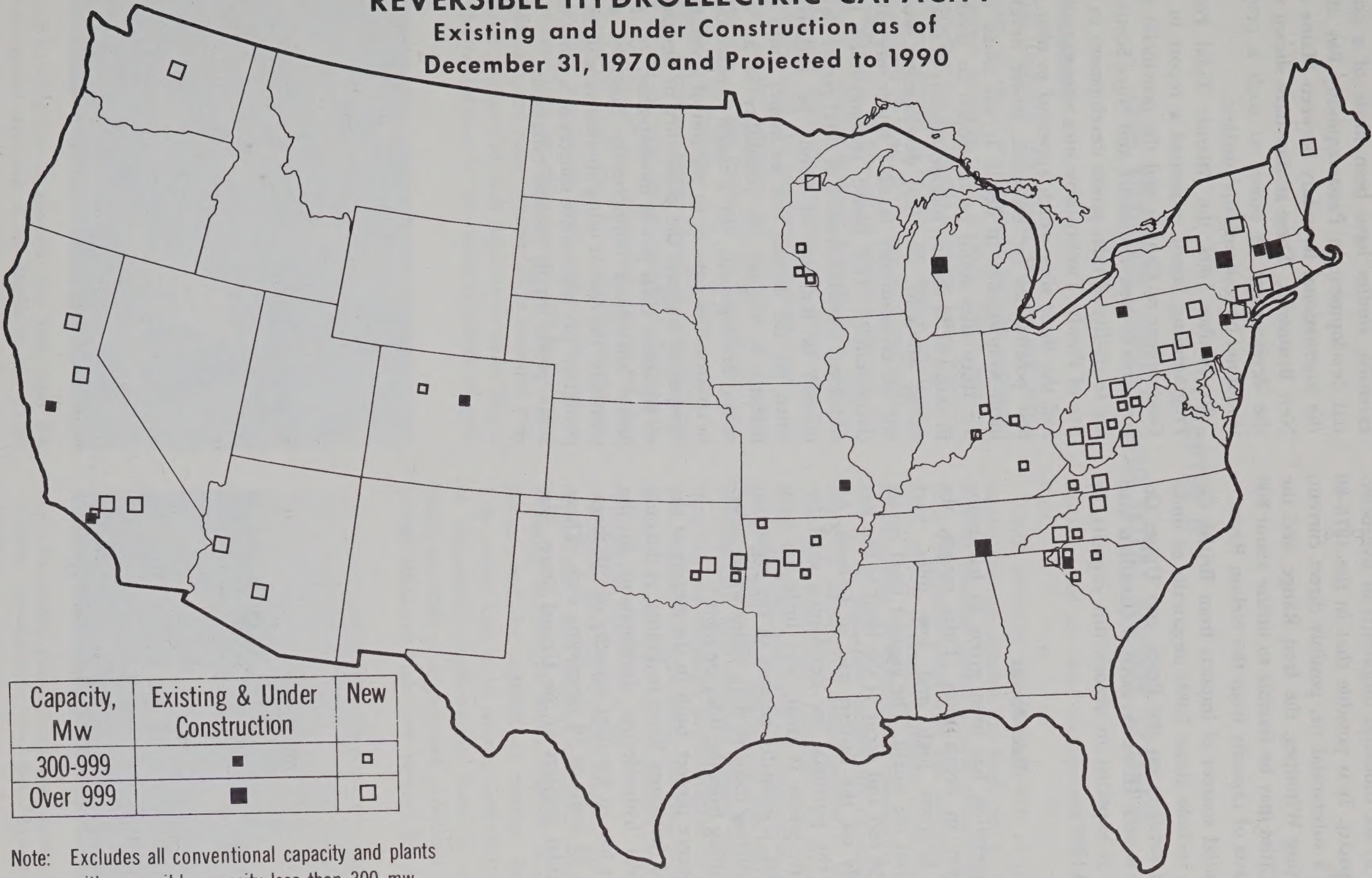

CONVENTIONAL HYDROELECTRIC CAPACITY
New and Expanded
Projected to 1990
Capacity, Mw
Expanded
New
100 - 499
Over 499
Note: Excludes all reversible capacity and conventional capacity in plants or plant additions of less than 100 mw.

Figure 7.13

REVERSIBLE HYDROELECTRIC CAPACITY
Existing and Under Construction as of December 31, 1970 and Projected to 1990



Capacity, Mw	Existing & Under Construction	New
300-999	■	□
Over 999	■	□

Note: Excludes all conventional capacity and plants with reversible capacity less than 300 mw.

Figure 7.14

of five to six thousand megawatts of hydroelectric capacity. It is possible that in the 1975–80 period a substantial tie, possibly direct current, connecting Winnipeg, the Iron Range, and the Twin Cities may be feasible to utilize about 800 megawatts of capacity from the Nelson River.

Potential sources of imports from British Columbia include about 7,000 megawatts of undeveloped capacity on the Peace and Upper Columbia Rivers. However, normal Canadian load growth is expected to absorb this capacity by the mid-1980's.

Tidal Power

Consideration has been given to harnessing the power in ocean tides. Tidal ranges, the height between high and low tides, vary throughout the world. The greatest tidal ranges exceed 50 feet and occur at the head of the Bay of Fundy off the eastern cost of Canada. Although the potential for developing tidal hydroelectric power is great, very little has been developed, principally because of the great cost of constructing dams in deep water where velocities resulting from the tides are high.

The Rance project, built in the estuary at the mouth of the Rance River in France, is the only large tidal hydroelectric development in the world. It has an installed capacity of 240 megawatts in 24 units of 10 megawatts each. There are no tidal projects in the United States, but extensive studies have been made of a potential development in Passamaquoddy Bay along the international boundary between Maine and New Brunswick. These studies have shown that the development of power at such a project would not be economically justified.

In October 1969, the Atlantic Tidal Power Programming Board submitted a report to the Government of Canada and the provincial governments of New Brunswick and Nova Scotia on the feasibility of tidal power development in the Bay of Fundy. Twenty-three sites were examined and the three sites which appeared to offer the best possibilities for economic power development were studied in detail. It was found that the three sites could be developed to produce in excess of 13 million megawatt-hours of electric energy annually, but that development would not be economically feasible under prevailing circumstances. The Board recommended that additional detailed studies of tidal power development in the Bay of Fundy be authorized when (a) the interest rate on money drops sufficiently to suggest the possibility of an economic development; (b) a major breakthrough in construction costs or in the cost of generating equipment suggests the possibility of designing an economic tidal power development; (c) pollution abatement requirements magnify, substantially, the cost of using alternative sources of power; or (d) alternative sources of a more economic power supply become exhausted.

CHAPTER 8

GAS TURBINES, DIESELS, AND TOTAL ENERGY SYSTEMS

Introduction

Gas turbines and diesel engines are prime movers of small to intermediate size compared to steam turbines used to drive large, modern generating units. Diesels have for years been the principal source of energy on many small electric systems to meet both base load and peaking requirements. A few small systems use gas turbines in a similar manner. Gas engines, gas turbines, and diesel engines are the prime movers generally used to produce electric power for "total energy" systems, or to serve as backup generation in the event of the loss of the normal source of supply.

The principal applications of gas turbines and diesels on large power systems include peaking, standby service, emergency power for safe rundown or black start at steam-electric plants, end-of-line regulation, and reserve. Because of short lead time for manufacture and installation of gas turbines, many systems have installed substantial amounts of such capacity to offset delays in the completion of the desired source of generation, and to meet unexpected increases in load.

Until recently, the load growth of predominantly thermal systems has been met by installation of efficient steam-electric generating units, thus displacing older and less efficient thermal units into a peaking or reserve operation. Such an expansion procedure was reasonably satisfactory when each new increment of capacity reflected a substantial improvement in efficiency over units previously available. As larger units were installed and rates of steam-cycle improvement slowed, that procedure did not always provide the best over-all system economy. It then became necessary to investigate the alternatives offered by combining peaking capacity of various kinds with more efficient but higher capital-cost base-load units.

Ideally, peaking capacity should be: low in capital cost, able to start quickly, operate satisfactorily at partial load, require little manpower, and be capable of remote operation. Low energy cost is, of course, desirable, but it is of secondary consideration because relatively small amounts of energy are produced. Even if energy costs are high, low annual fixed charges

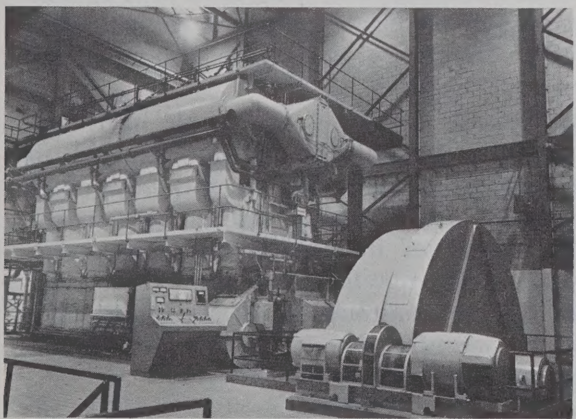


Figure 8.1—The City of Freeport, New York, owns this 9.5-megawatt unit, one of the largest in the United States.

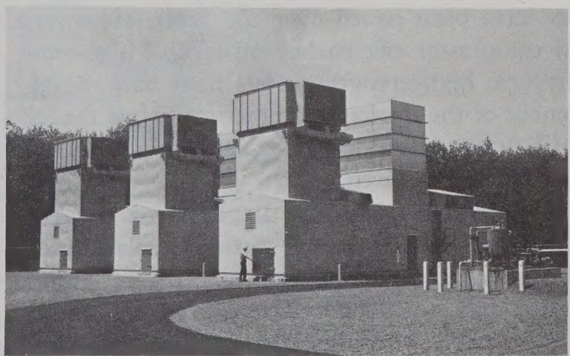


Figure 8.2—Boston Edison Company's Substation in Framingham, Massachusetts, has three 15-megawatt gas turbines.

and labor costs may make gas turbines or similar types of capacity the most economic choice.

Gas Turbines

The combustion gas turbine consists typically of an axial-flow air compressor, one or more specially constructed combustion chambers where liquid or gaseous fuel is burned in an excess of air, and a power turbine of two or more stages where the hot gases are expanded to drive the compressor and generator. Basic elements are illustrated diagrammatically in figure 8.3. Compression ratios are typically in the order of 8:1 to 14:1 for industrial and aircraft types, respectively. Nearly two-thirds of the total turbine horsepower is required to drive the compressor. Temperature of the gas stream entering the turbine will be about 1800°F at peak rating and exhaust temperatures will be 950°F or slightly higher.

The appeal of the gas turbine plant lies mainly in the fact that it is a simple rotating machine which requires no boiler, boiler water and water treatment; needs no condensing water, and therefore rejects no heat to water bodies; requires a minimum of power-consuming external auxiliaries; and involves minimal siting, housing, and foundation problems. The sulfur dioxide emission depends on the sulfur content of the fuel being used, but it is normally low. Nitrogen oxide emissions are slightly higher than those of a comparable-sized fossil-fueled steam-electric unit.

The concept of the gas turbine goes back into the early history of energy conversion devices. In 1791, a patent was issued on the basic features of the gas turbine, and various other patents have been issued over the years. However, low compressor efficiencies and lack of high-temperature, high-strength metals held back development of the device as a practical prime mover until demands for higher speed aircraft forced the necessary research.

In its earlier phases of development, a great deal of study and research was devoted to investigation of complex design concepts to attain high energy conversion efficiencies with little regard to costs. Multi-stage compression with intercooling was employed as was regeneration to afford partial recovery of heat remaining in the exhaust gases after they have expanded through a multi-stage turbine element. Regenerators and complete cycle systems are illustrated in figures 8.4 and 8.5. Brown Boveri, a Swiss firm, built a two-stage 27,000-kilowatt set having a guaranteed efficiency of 34 percent as early as 1947.

Precooling, intercoolers in the compression phase, and regenerative elements add considerably to the cost and complexity of the installation and are not readily adaptable to the aircraft type of gas (jet) engines so extensively employed today. Precooling and intercooling require substantial amounts of water with associated pumping and possibly cooling tower facilities. Both coolers and preheaters impose some additional pressure losses on the gas stream, and the added complexities increase start-up and loading time from a very few minutes with the aircraft-type jet engine units to a half hour or more for the so-called "complete cycle" installation. To date, the utility industry has not employed these more efficient but more costly and complex cycles because the fuel saving for the usually short periods of operation does not justify the extra investment. The most efficient compressor in general use in 1970 is the axial flow type introduced commercially shortly after 1900 and since improved to its present efficiency of approximately 85 percent.

The simple open-cycle gas turbine-generator unit is the gas turbine design most widely used by the industry today. It has a low capital cost of $80 to $100 per kilowatt, is relatively quick starting, is compatible with a wide choice of site locations, and is readily automated. Following the widespread power interruption in the Northeast in November 1965, these units have become increasingly popular as sources of reserve power and for providing start-up power in case all system power has been lost.

Single unit plants of the simple open-cycle type are pre-engineered and pre-packaged to minimize field labor. Units on the order of 20 megawatts are shipped assembled, but larger ones are erected in the field on concrete slab foundations. Typically, plants include provision for remotely controlled unattended operation, and are furnished with a self-contained cooling system and weatherproof housings.

The gas turbine has received rather wide application as an industrial prime mover, and starting in the early 1950's has been used in peaking and end-of-line applications for voltage

SIMPLE OPEN-CYCLE GAS TURBINE

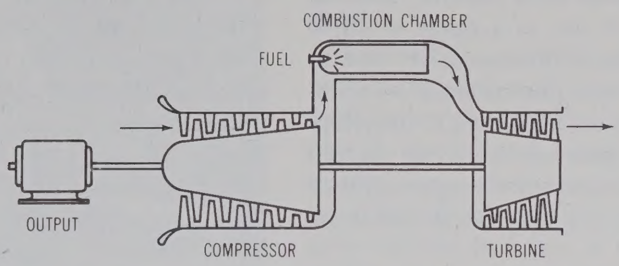


Figure 8.3

SIMPLE OPEN-CYCLE GAS TURBINE WITH REGENERATION TO RECOVER PART OF THE HEAT IN THE EXHAUST

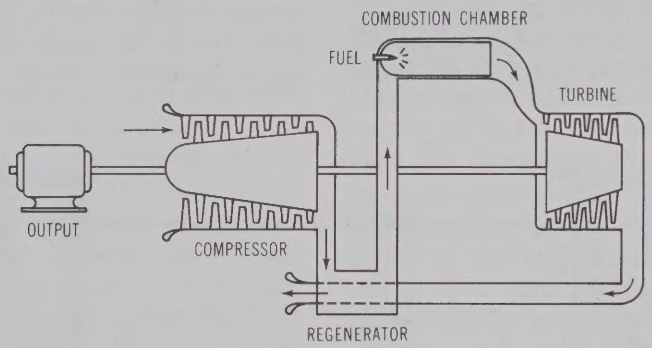
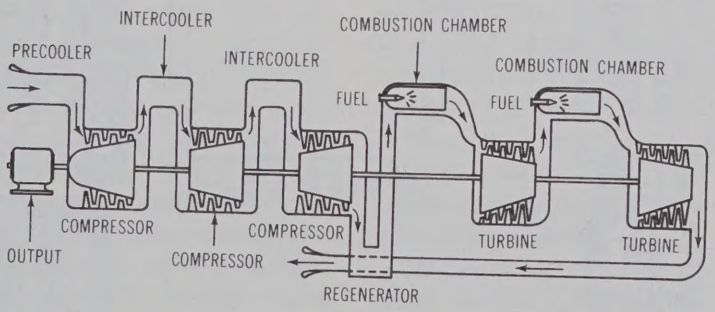


Figure 8.4

COMPLETE-CYCLE GAS TURBINE 1/



1/ This Complete Cycle has multiple compression stages with intercooling, two stages of combustion and expansion, and regeneration to recover part of the heat in the exhaust.

Figure 8.5

control in the electric utility industry. Early applications were in sizes of 5 to 10 megawatts. Since about 1960, combustion turbine installations have increased in size to a range of 18 to 60 megawatts on a single turbine drive, and to 160 megawatts, using multiple turbines on a single generator shaft (see figure 8.6). Development work is in progress on units up to 100 megawatts with gas turbine inlet temperatures of 2000°F and above. These may be available by 1980.

Combustion turbines are equipped to burn either liquid petroleum fuels or natural gas, and may be installed to burn either fuel interchangeably. Most manufacturers are marketing an arrangement which permits changing between liquid and gaseous fuels while operating under load. Liquid fuels used are light petroleum distillates with a viscosity similar to kerosene or light fuel oil, typically the type used in aircraft. Liquid fuel prices are subject to considerable variation, and in 1970 were in the range of 70 to 90 cents per million Btu. Natural gas, when available at off-peak rates, may cost approximately half this amount. However, if the unit is to serve the function of firm capacity for peaking and reserve, it must be capable of operation at all times. Thus, the most common arrangement is a dual fueled installation using liquid fuel only when natural gas is not available. Residual and crude oils are being considered for use by newer gas turbine units and some units are being sold with this capability.

Since the combustion turbine uses large volumes of air, and compressor speeds are very high, sound suppression treatment is required to keep noise levels within reasonable limits. Commonly, silencers are employed on both intake and exhaust. Manufacturers claim that with appropriate treatment, noise can be reduced to levels which would permit installation in residential neighborhoods. Most installations, however, are in the yards of existing plants or at major substations where adequate space may be

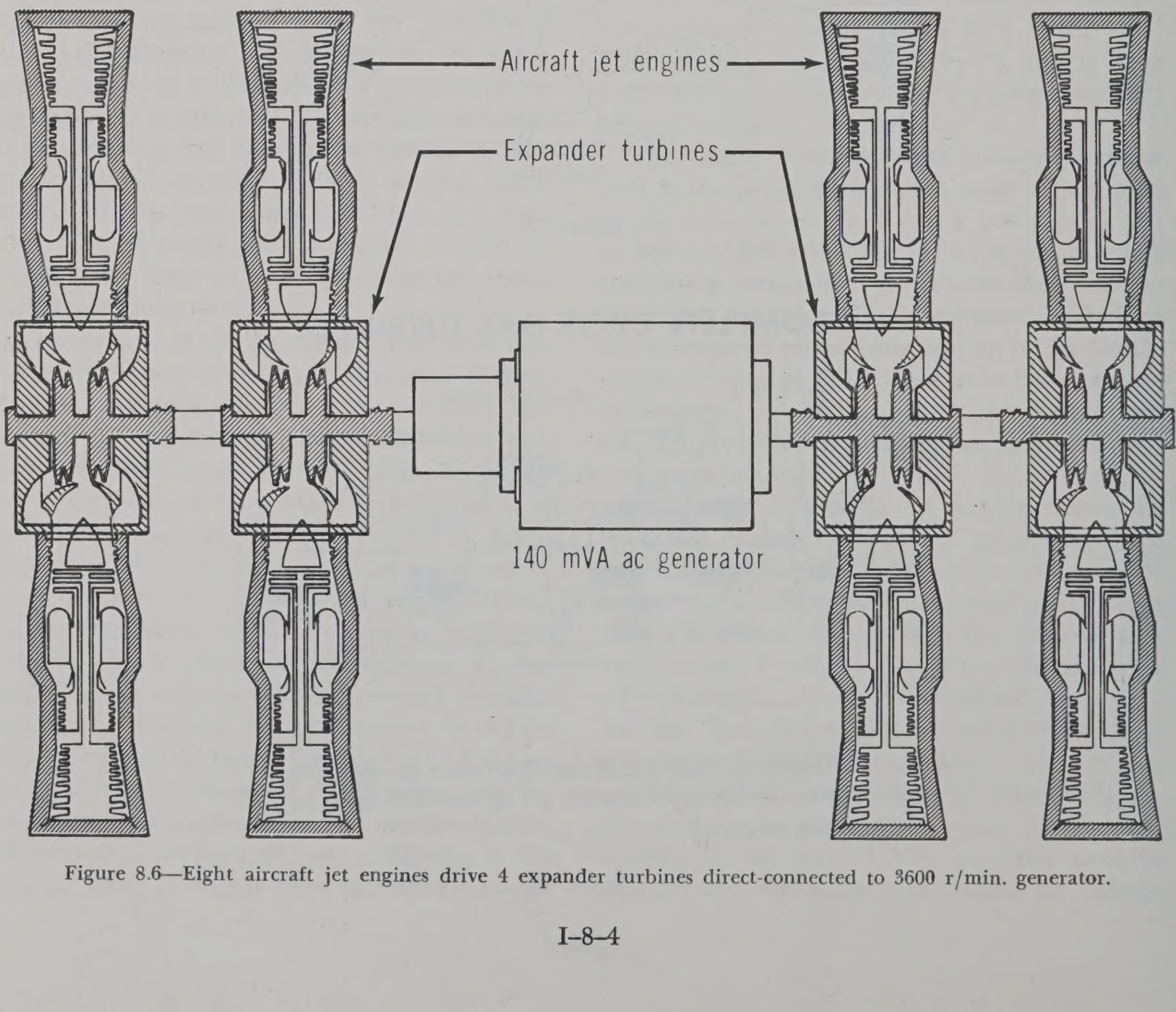


Figure 8.6—Eight aircraft jet engines drive 4 expander turbines direct-connected to 3600 r/min. generator.

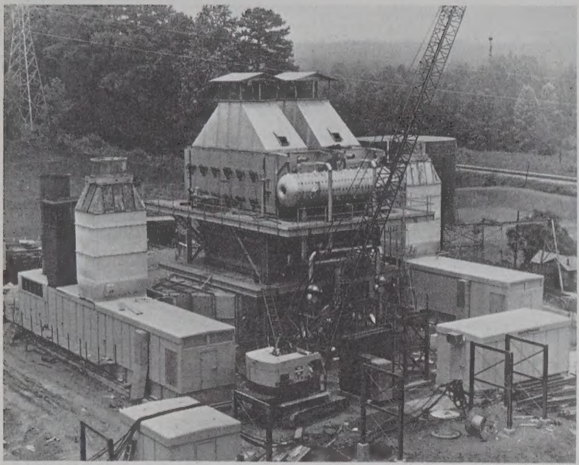


Figure 8.7—South Carolina Electric & Gas Company's gas turbine and heat recovery complex. Waste heat from the turbines, augmented by oil or gas heat, produces steam for use at the nearby Parr Steam-Electric Plant.

available and connections with the transmission network can be made at minimum cost.

Aircraft type gas turbines are used extensively for electric power generation. Modifications of aircraft jet engines provide a high energy flow of hot exhaust gas which serves as the working medium to drive the expander turbines and electric generator. For these units, the expander turbine is a separate unit directly connected to the generator shaft, thus eliminating geared drive. The entire jet unit may be removed for maintenance and replaced with a spare (in some cases, a factory exchange unit) in about eight hours.

Operating labor costs for gas turbine units are low since the plant is generally automated. Maintenance requirements vary widely depending upon such factors as loading and fuel quality. Both aircraft and industrial type gas turbines require on-line inspection every 500 to 1,000 hours of operation, and a major overhaul after 2,000 to 5,000 hours operating time if run at normal loads and reasonable capacity factors. Maintenance costs would be higher on units which are started frequently and run for short periods.

Units normally can be started, synchronized, and loaded automatically within 5 to 20 minutes, and with some recent designs emergency starts can be made in as little as three to five minutes. This feature alone can provide significant start-up and standby savings when compared with steam peaking capacity as an alternative.

Combustion turbine generating units are usually installed with a view to operating 500 to 1,000 hours per year on load. Since they can be quickly started and loaded, they serve as ready reserve even when shut down. Full load heat rates, based on the high heating value (HHV) of petroleum fuel, are in the order of 12,500 to 15,500 Btu per kilowatt-hour for current designs, and may range upward to 17,000 Btu for earlier units. Low-load heat rates are so high that units are usually operated at or near full load when needed, then completely shut down.

In order to overcome some of the problems and limitations imposed by temperatures and materials, and to provide peaking units of larger size, two manufacturers have developed and offered for sale a steam injection gas turbine concept with units of 200 megawatts. The cycle employs a steam boiler and a steam turbine, the output of which matches requirements of an axial-flow compressor providing combustion air for a double flow gas turbine which, in turn, drives a 200-megawatt electric generator. Water is fed to the boiler where steam is generated which then passes through the noncondensing steam turbine on its way to the combustion chamber. Air from the axial-flow compressor provides combustion air in the primary zone, and the steam being introduced into the secondary zone cools the products of combustion. This mixture is expanded through a double flow gas turbine, then through the boiler for waste heat recovery before exhausting to the atmosphere. The boiler requires supplemental firing to provide sufficient steam to balance the cycle and to maintain the unit in condition for quick start-up in an emergency. The steam cycle requires 100 percent make-up water, but this may not be excessive for low capacity factor (peaking) operations in many areas.

The manufacturer's performance curve for the steam injection peaking plant indicates a heat rate of approximately 14,900 Btu per kilowatt-hour at full load increasing to about 16,300 Btu per kilowatt-hour at 50 percent load. These heat rates are in the same range as those of combustion turbine units. A two-unit, 400-megawatt plant might be expected to cost in the neighborhood of $75 to $100 per kilowatt, depending on

site conditions and other factors. To date, none has been put in service.

Combined-cycle units may find use in the future as intermediate cycling units filling longer term use, justifying the higher cost in return for better efficiency. The capacity of the 133 megawatt plant shown in figure 8.8 is greater than the total of the separate capacities of the 25 megawatt gas turbine (on the left) and the 85 megawatt steam turbine (on the right). The exhaust from the gas turbine is used as precombustion air for the boiler serving the steam turbine. The prospects for combined cycle gas turbine-steam turbine applications are discussed in chapter 5. The possible use of a gas turbine in combination with a high temperature gas-cooled nuclear reactor to produce base-load power is discussed in chapter 6. Research and development efforts in the gas turbine field are covered in chapter 21.

Installations and Scheduled Additions

There were more than 500 gas turbine units in operation at the end of 1970. Those units provided about 15,000 megawatts of capacity. Substantial amounts of additional gas turbine capacity are on order or planned for 1971 and later. Gas turbines will then constitute as much as 20 percent of the total capacity of some systems. In some instances, this may result in the necessity to operate gas turbines more hours per year than may generally be desired. However, if delivery and installation schedules on other types of capacity improve, so that the utilities can confine new installations to base load type of capacity additions, the situation should correct itself through growth in system loads.

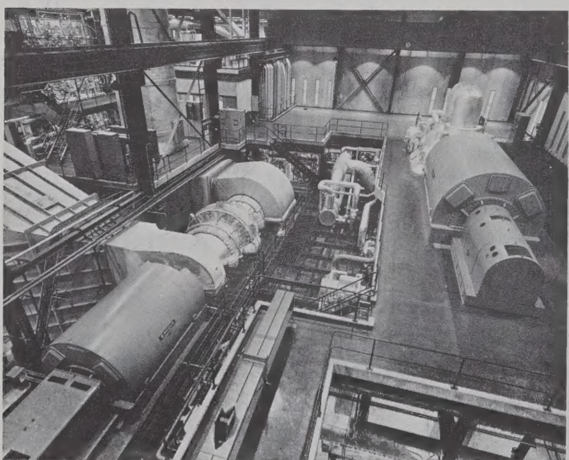


Figure 8.8—West Texas Utilities Company's combined cycle 133-MW gas and steam turbine installation at the San Angelo power plant.

Gas turbine installations are expected to increase from about 15,000 megawatts in 1970 to 32,000 megawatts in 1980 and 63,000 megawatts in 1990. This reflects a minimal increase from 4.4 percent of total utility capacity in 1970 to 5.0 percent in 1990. These estimates do not include gas turbine prime movers which may be incorporated as part of the conventional steam turbine cycle or magnetohydrodynamic generation, or which may find application in conjunction with the high temperature gas-cooled breeder reactors. Such installations are not expected to provide significant amounts of new capacity prior to 1990.

Diesel Engines

Diesel engine-generator units for central station power service generally fall into two broad categories. Those of the slow speed, heavy duty base load design (see figure 8.9) or of the intermediate speed, lighter weight, prepackaged building-block type (figure 8.10), the latter are generally about two megawatts in size. The former are manufactured in sizes to approximately six megawatts domestically, and are reportedly offered in sizes of 20 to 25 megawatts by some foreign manufacturers.

Diesel engine units have been used for both base load and peaking operations for many years. The diesel cycle offers relatively high

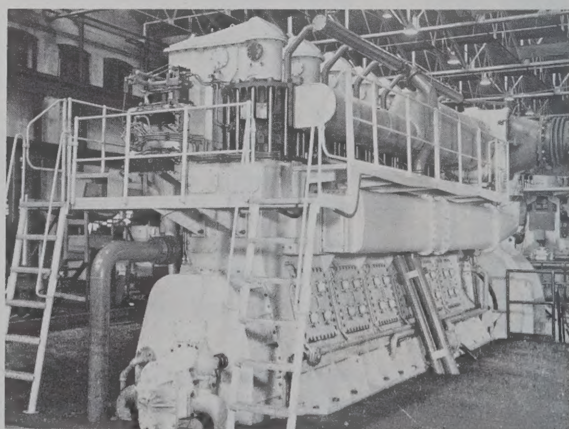


Figure 8.9—Six-cylinder 6,000-horsepower Fairbanks Morse diesel generator set.

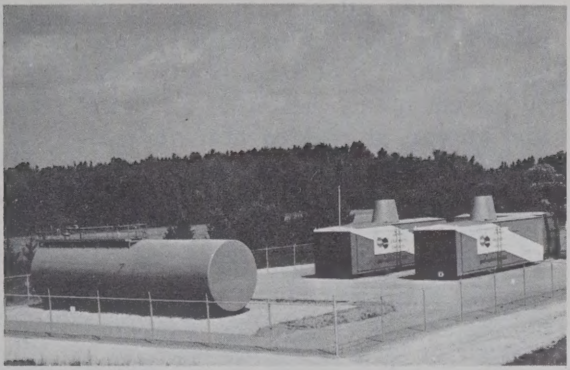


Figure 8.10—These two 2-megawatt diesel units, owned by Wisconsin Public Service Corporation, are designed for automatic operation or for remote control operation.

efficiency over the entire size range in which the units are manufactured. Diesel engine units are much more efficient both at full and at partial loads than either gas turbine or small steam turbine units. Diesel units can be started and fully loaded in less time than any other form of generation except hydro.

Diesels are capable of remote start and complete supervisory or automated operation. A principal drawback is that even in the largest sizes commonly manufactured domestically, they are smaller than is usually desired in expanding modern systems.

Straight diesel, supercharged diesel, and dual fuel engines are available. Typically, each engine is mounted on a structural steel base and is enclosed, together with lubricating and cooling equipment, and all other accessories, in a sound suppressing and weatherproof housing. Necessary automatic control equipment is housed in a separate control cubicle. These packaged units can be shipped on freight cars and trucks to the site and installed outdoors. Very little is required in the way of foundations which may consist of crushed rock and railroad ties or simple concrete piers. The packaged diesel units are obtainable in ratings from 1,100 to 2,750 kilowatts and are usually combined to provide plants of two to four units. One utility company has installed 11 units at one site.

Diesel units offer wide latitude for site location. As in the case of the gas turbine, only a small amount of make-up cooling water is required. A piped-in fuel supply is needed if the unit is to operate on natural gas.

Current installed cost per kilowatt is approximately $100 for the larger installations and the heat rate under full or partial load is about 12,000 to 13,500 Btu per kilowatt hour.

Diesel units are well-suited, both operationally and from the standpoint of fuel economy, to part-load operation. They can be efficiently operated under lightly loaded conditions as they provide spinning reserve. This feature is a distinct advantage contrasted to gas turbines, whose no load fuel requirements approach 50 percent of those for full load operation. Other favorable features of diesel units include portability, very short installation time, and availability in small ratings for close load matching.

Many utilities are installing diesel generators in large steam-electric plants to provide emergency capacity for safe shutdown and to permit plant start-up when isolated from outside sources of power. The larger power systems seldom install diesels for peaking use only. Portable units are sometimes moved to serve better the needs of the system. Diesel electric generating capacity for general utility service is expected to increase from about 4,000 megawatts in 1970 to 8,000 megawatts in 1980 and to 12,000 megawatts in 1990.

Total Energy Systems

A total energy system provides on-site generation of electric power for lighting and all other electric requirements and the utilization of all or part of the waste heat created by this generation for space heating, air conditioning, water heating, steam production, etc., to meet all the energy requirements of the project owner. Each total energy system is, in fact, a mini-electric utility system; faced with the same problems of: diversity, reserve capacity, maintenance outages, and equipment failure. The total energy system usually must rely entirely on its own resources to meet peak demands and provide for regularly scheduled maintenance work and emergency outages, whereas the central station can usually depend on the interconnected network for assistance in time of trouble. Conversely, the total energy system is not affected by external network disturbances.

Total energy installations vary with the many combinations of prime movers, fuels, heat recovery systems, cooling units, power requirements,

and users of recovered heat. Historically, on-site generation has been a by-product of industrial operations where the prime need was process steam. However, in recent years there has been increasing interest in total energy systems for shopping centers, motels, apartment complexes, schools, and similar types of markets, primarily because of: (1) the almost universal use of air conditioning, (2) the widespread use of absorption refrigeration equipment, (3) the development of sophisticated automatic control equipment, (4) improvements in the gas turbine, (5) widespread availability (until very recently) of natural gas via high-pressure gas transmission lines, and (6) the use of high-frequency lighting and high-speed motors. The promotional activity of the natural gas companies has been a necessary catalyst to the rise of total energy systems.

The two currently predominant types of prime movers for total energy systems are the reciprocating engine and the gas turbine. The reciprocating engine is versatile and reliable as a power source and heat can be recovered from the water jacket, lubricating system, and exhaust. Gas turbines are being used at an increasing rate because of their mechanical simplicity, inherent reliability, and the availability of exhaust heat at a positive pressure and a temperature range of 700 to 1000°F. There are a few instances where both reciprocating engines and gas turbines are being utilized together in total energy systems. The number of plants in operation by type of prime mover is given in table 8.1.

For the most economical operation of a total energy system, the rejected heat of the prime mover should substantially and simultaneously balance the heat requirements because the storage of rejected heat is not practical. Since 60 to 80 percent of the fuel input for power generation appears as rejected heat, its recovery is a fundamental consideration in the economic feasibility of a total energy system and the use of this recovered heat for both heating and cooling is essential for satisfactory energy utilization. Cooling equipment of the absorption type predominates over compression refrigeration since it uses the heat energy of low-pressure steam, rather than mechanical energy, to operate the refrigeration cycle.

There is no simple method for analyzing the economic feasibility of a total energy system. Each proposed installation must be investigated individually, considering all capital revenue requirements and all operating costs, such as fuel, labor, supervision, lubricating oils, water re-

TABLE 8.1

Total Energy Systems[1]

Type of Prime Mover	No. of Plants
Gas turbine	58
Gas engine	259
Diesel engine	27
Dual-fuel engine	17
Combination (more than one of above)	17
Steam turbine	[2] 5
Total	383

[1] From TOTAL ENERGY (January 1971).

[2] Three of these plants also have other prime movers installed.

TABLE 8.2

Total Energy System Installations[1]

Category	No. of Plants
Apartments	22
Building materials	10
Cattle feeders	4
Dairies and creameries	3
Data centers	9
Educational institutions	35
Feed and grain	7
Government facilities	6
Hospitals and clinics	14
Hotels and motels	12
Manufacturing and process	80
Meat packing	3
Mining	2
Office Buildings	
Gas companies	[2] 43
Other	19
Radio, TV stations	4
Recreation centers	3
Repair shops	2
Service centers	
Gas companies	[2] 26
Other	13
Shopping centers	30
Stores and markets	8
Other gas company facilities	[2] 14
Others	14
Total	383

[1] From TOTAL ENERGY (January 1971).

[2] The total of the gas company installations is 83.

quirements, the overall heat balance throughout an operating year, and the system reliability.

The total energy concept is being applied to a wide range of customer categories as shown in table 8.2 which lists total energy installations in operation in 1971. Since 1962 there has been an annual growth of approximately 90 megawatts in total energy systems. The Edison Electric Institute reports that 20 total energy systems had been shut down for various reasons and shifted to the use of purchased power prior to January 1968. These 20 systems had an installed capacity of 15 megawatts. Probably the three principal reasons why some local energy systems have not proved satisfactory are: (1) excessive operating and maintenance costs, (2) inadequate reliability, and (3) insufficient firm capacity for connected load. Despite the shutdown of a number of total energy projects, experience has demonstrated that they can be a reliable source of electric service if properly designed with adequate load-carrying capability, an adequate reserve generating supply, a good control system, and an adequate maintenance program.

It appears that total energy systems will continue to be installed in industrial processing plants, and commercial establishments, where an economic balance exists between power and heating loads. Presently, single dwelling units do not appear adaptable to total energy systems as conceived because of their relatively small energy requirements. Future expansion in use of total energy systems is difficult to predict because the economics and reliability of these systems is still uncertain without an alternate or emergency source of supply.

A movement is developing within the electric utility industry to embrace the responsibility of providing not only electric service but also heating and cooling in areas of concentrated demand. In some instances, this may be accomplished by utility ownership of on-site generating facilities coordinated with central station service. Electric utilities probably could meet the customers' needs on a more reliable basis and with more flexibility than can be achieved with individual customer ownership. If total energy systems find a sizable place in serving electric power requirements in the future, it appears likely the electric utility industry will enter the field.

CHAPTER 9

OTHER FORMS OF GENERATION

Introduction

The search for new forms of generation is prompted by the utility industry's constant effort to improve operating efficiency, military and space requirements, and the need to find new sources of energy to provide power with relatively less impact on the natural environment.

Researchers throughout the world have been investigating many sources of energy in their efforts to develop new generating methods. The researchers have demonstrated the technical feasibility of producing electricity from heat sources in the earth and from the energy of the sun, wind, waves, and tides, as well as falling water. They are considering the possibility of harnessing the earth's magnetic and gravitational fields, the earth's rotational energy, and the energy stored on the moon's surface by years of electron bombardment from the sun. Generating methods related to these energy sources have been investigated to determine the degree of promise they hold and the usefulness of applicable technology in other fields.

Of the many research efforts, several that hold particular interest for the utility industry are thermionic, thermoelectric, solar and geothermal generation; fluid-dynamic converters, the nuclear fusion reactor, and the development of fuel cells. Nuclear researchers are also actively involved in the development of breeder reactors to optimize the use and increase the availability of nuclear fission fuels. A discussion of the breeder reactor program is presented in chapter 6.

Most major thermal electric generating units today include massive rotating devices which act as thermal-energy converters. Fuel is burned to develop heat energy. The heat energy is translated into mechanical energy and the mechanical energy, in turn, transformed into electrical energy. In such thermo-mechanical processes the overall efficiency is inherently limited by basic thermodynamic principles. Even with no mechanical losses within the system the thermal efficiency is limited by the inlet and exhaust temperatures within which the system is to operate. This is called the Carnot cycle efficiency and is expressed as a ratio of the inlet-exhaust temperature differential to the inlet temperature $\frac{T_i - T_e}{T_i}$ measured in absolute degrees. Practical systems involve internal losses and therefore can only approach Carnot efficiency. Past efforts to increase the efficiency of these systems strove to improve the Carnot efficiency and to improve the technology used to transform energy from one form to another. Since all heat engines must ultimately exhaust to the ambient environment, efforts to improve the Carnot efficiency have been directed toward increasing the inlet temperatures. Results have been limited, however, by the ability of available materials to withstand mechanical stress at high temperatures. Fossil fueled steam-electric generating units being installed today have overall efficiencies of nearly 40 percent. Because of their massive size, enormous rotational stresses and steam temperatures and pressures, the units operate at or very close to the metallurgical and mechanical limits of the materials used in their construction. The difficulty of obtaining additional economic increases in efficiency within these systems, and recent developments in other technological areas have led to consideration of other electrical energy systems; particularly those involving direct energy conversion. Such systems would eliminate intermediate energy transformation stages and the massive rotational stresses, thereby allowing the use of higher inlet temperatures and making possible the attainment of higher overall efficiencies. Most of the new generating methods

discussed below are of the direct energy conversion variety, and possess these characterisitcs. Many of the systems also hold considerable promise for reduction of adverse effects on the environment.

None of these other forms of generation appear to provide an immediate solution to any of the problems facing the utility industry today. Several of the processes being studied are realizing limited success in small to moderately-sized installations, notably geothermal generation and the fuel cell. Geothermal power will be expanding appreciably by 1990, but will not be generally available to the entire industry. Wide-scale application of fuel cells in central station generation seems an unlikely eventuality. They may, however, be developed for at-site applications and use in substations, possibly by 1980. Most promising in the near term for central station generation is MHD, but a substantially increased support level will be required if this potential is to be realized. Other techniques such as thermionic, electrogasdynamic, or thermoelectric generation seem much further away, barring significant technological or commercial breakthroughs. Direct utilization of solar energy for bulk power generation, attractive largely because of the ready availability of this resource, appears to be even more remote. Perhaps the greatest potential for the future lies in the controlled fusion reacton, but even with a commitment today it might require many years beyond this survey's target date of 1990 for a timely development of this technology.

Magnetohydrodynamics

Magnetohydrodynamic (MHD) power generation is accomplished by passing a hot ionized gas, or liquid metal, through a magnetic field. Substitution of the fluid conducting medium for the rotating metallic conductor of existing turbogenerators enables the utilization of high temperature (4000–5000°F), one stage conversion devices which offer higher overall efficiencies. Though the concept of MHD generation has been known for over 100 years, it is only in the past decade that significant technological advancements have produced systems which offer promise for use in the electric power field.

Three basic approaches to MHD generation are being explored today. These are broadly classified as open-cycle, closed-cycle, and liquid-metal systems.

Open Cycle

The basic open-cycle system consists of a high temperature rocket-like combustion chamber, a conduit or channel to transmit hot ionized gas through a magnetic field, and a high performance magnet to establish the necessary magnetic field. It employs a working gas produced by the combustion of fossil fuels and the addition of compounds (seeding) containing easily ionizable elements which are introduced to increase the electrical conductivity of the gas.

The combustion of fossil fuels in an atmosphere of oxygen-enriched and/or preheated compressed air containing seed material develops a high temperature, highly ionized, gas. The gas is released, at very high velocities, through the combustion chamber exhaust nozzle and passes through an MHD channel and magnetic field, inducing a dc voltage between electrodes imbedded in the channel walls.

MHD open-cycle generation, used as a "topping unit," in conjunction with present steam-turbine generation, appears to hold the most promise for MHD central-station power generation in the near future. Utilizing the higher temperature characteristics of MHD to increase inlet temperature and the MHD exhaust heat to supply steam for steam-turbine generation, the overall system efficiency is expected to be increased to a range of 50 to 60 percent, and thus provide fuel savings of 20 to 30 percent over fossil fueled steam-electric plants. General application of coal-fired MHD topping units by the mid 1980's could result in overall savings that would aggregate billions of dollars by the end of the century. It could effectively extend fossil fuel reserves and also enhance interfuel competition by improving the competitive position of coal. In addition, the MHD generator would require little cooling water and the combination MHD-steam units would require considerably less cooling water per megawatt of capacity than conventional fossil-fueled and nuclear steam-electric units.

However, before MHD can be utilized for central station power generation many problems must be solved. In general, open-cycle MHD research has not confronted the problem of burning coal or coal-derived fuels in an economically

practical system. Designs to date have been on a relatively small scale, have used cleaner fuels, and have produced much shorter operating lifetimes and lower efficiencies than would be acceptable in utility operation. Other problems involve the development of high temperature electrodes and MHD channels of long durability, economic superconducting magnets of sufficient capacity and reliability, technology to meet stringent requirements on seed recovery, and suitable auxiliary components—notably an improved air preheater and coal handling system.

The high temperatures and gas passage times involved are conducive to the fixation of nitrogen. Air quality control may require development of technology either to restrict NO_x formation or to effect its removal from the stack gas. Due to the interrelated nature of many of these problems and overall system design, there is need for progressive development of experimental MHD systems which can be used to evaluate progress and determine future courses of action. Simplified representations of open-cycle MHD generation and a combined MHD-steam generator are shown in figures 9.1 and 9.2, respectively.

MHD generators of various types have been successfully demonstrated in several areas of the world but in general the units are of moderate size and are used primarily as research vehicles or development tools. The countries involved in the research include England, France, Germany, Japan, Poland, the Soviet Union, and the United States. For the most part, research programs are directed toward solving component performance problems such as electrode technology, but those at Swierk, in Poland, and Moscow, in the Soviet Union, are large installations designed for extensive central station power plant research.

OPEN-CYCLE MHD GENERATION

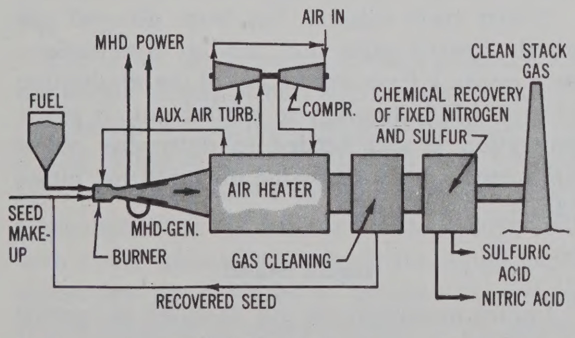


Figure 9.1

COMBINED OPEN-CYCLE MHD - STEAM GENERATION

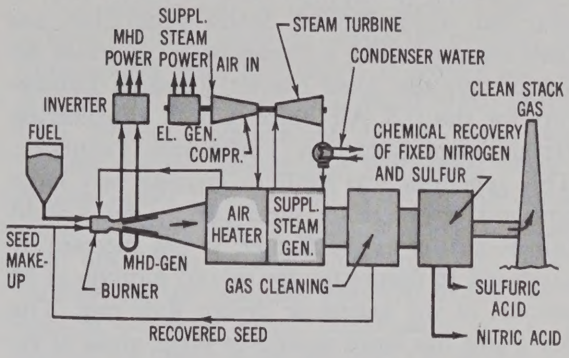


Figure 9.2

The Soviet Union appears to have made a strong commitment to the development of MHD for commercial use. A 75-megawatt (net) combination MHD-steam pilot plant is being constructed near Moscow. For the present, only the 25 megawatt portion of the plant will be completed and operated, presumably due to a shortage of funds. Eventually the unit will be used to explore all aspects of technology and to evaluate the economics of large MHD power plants. The unit is to be fueled by natural gas initially but, with the solution of certain practical problems, coal or oil firing is expected to be more economical. The Soviets are also constructing what will be the largest experimental MHD facility in the world at the Krzhizhanovsky Institute of Power Engineering in Moscow, and Soviet engineers express confidence that an open-cycle MHD unit of appreciable power output will be operating in the 1970's.

Japan is also actively engaged in MHD research and has made great strides in achieving the high field superconducting magnets necessary for central station MHD operation. Additional work is still necessary to develop such magnets economically but considerable potential for reducing costs is evident and MHD researchers are confident this will be accomplished in the near future.

Utility companies, manufacturers, and research institutions in the United States have been actively involved in MHD investigations since the 1950's. Experimental generators constructed in the United States have produced

moderate outputs for short periods of time and small power outputs for hundreds of hours. A practical utilization of MHD generation has been reported to be a 20-megawatt generator developed by the Avco Everett Research Laboratory for the U.S. Air Force Arnold Engineering Development Center in Tullahoma, Tennessee. This generator was built to provide very large amounts of power for short periods for a wind tunnel facility at the Center. It has successfully produced 16 megawatts for several minutes at 80 percent of the generator design flow rate. The Air Force has since moved to other areas of research to meet the needs of their specific problem.

The open-cycle MHD system is also being considered for use in "topping" applications with gas-turbine generators. The systems studied show slightly lower efficiencies than topped-steam installations, but MHD gas turbine systems require virtually no cooling water and might possibly be used advantageously in arid areas. Coal char-fired MHD systems are also being considered as a means of enhancing the economics of coal liquefaction and gasification plants being studied by the Office of Coal Research.

In addition to the base load operation of MHD topping units, the open-cycle system has also been considered for use, without bottoming cycles, for emergency reserve and peaking applications. Since emergency reserve and peaking units are normally operated for relatively short periods of time, they must have low capital costs but may have relatively high operating costs. Because of the fast start-stop and possible low capital costs characteristics of the MHD system, oxygen-enriched, liquid-fuel MHD generators are being given consideration for emergency operation. Such systems would have operating costs which are too high for peaking applications due to the oxygen requirements and lower thermal efficiency of the simplified cycle. Peaking requirements would entail the addition of components to increase the efficiency of operation and would increase capital costs.

Some hope exists for the emergency and peaking applications of MHD technology. Several Northeast utilities and the Edison Electric Institute are financing a three-phase program to develop an experimental power plant using the simplified liquid fuel MHD generator. The development of a prototype generator fired by clean, liquid fuel is expected to produce some technology applicable to base load MHD units. The preliminary design and modeling of the simplified unit were completed in phase one of the project and the participants are proceeding with the detailed design. A 0.5 megawatt prototype is being built by Avco Everett Research Labs for use in this design study and also in a base-load program sponsored by the Office of Coal Research.

Closed Cycle Gas

Closed cycle gas MHD is somewhat similar to the open-cycle concept in that thermal energy is transferred to a seeded, working gas which is then passed through an MHD channel and magnetic field. Power is extracted from the MHD channel in much the same way in both systems. Closed cycle MHD is designed to operate at lower temperatures (3000–3500°F); utilizes a seeded noble gas, such as helium, as the working fluid; and requires the transfer of additional energy to the working gas after the working gas has been released from the thermal chamber. Materials problems, such as corrosion, erosion, ash deposits, and other corrosive mineral deposits, associated with heating a noble gas by combustion, make fossil fuel closed cycle MHD impractical. The system is of interest for central station power generation because it provides a means of utilizing the somewhat lower top temperatures potentially available from advanced fission reactors. To achieve required electrical properties in the seeded noble gas at temperatures in the range being considered, it is necessary to transmit additional energy to the electrons within the gas. The electrons are excited by sophisticated technical means beyond the stage produced by thermal energy and achieve energy levels equivalent to temperatures many times that of the gas itself.

Closed cycle research has been directed primarily toward space and military applications. As a result, a fresh evaluation of the application of available technology to central station power generation is still needed to determine potential benefits and to provide direction for future efforts.

Liquid Metal

Liquid metal systems are designed to operate at still lower temperatures (1500°–2000F°) than

closed gas systems. The liquid metal working fluid has higher electrical conductivity and it is not necessary to obtain extremely high temperatures to accomplish MHD generation. High power densities possible in the liquid metal systems also eliminate the need for superconducting magnets to establish a satisfactory magnetic field. The higher conductivity also makes the generation of ac power possible with liquid metal MHD systems and could eliminate the need for dc to ac inverter systems. The elimination of inverter systems, and air preheater and seed recovery equipment would reduce the capital cost of installations but the major benefit associated with liquid metal MHD would be the simplification of problems concerning the MHD channel. Space technology has demonstrated successful long life containment of liquid metals such as potassium and sodium at temperatures of 2200°F in refractory metals and of 1600°F in some steels and superalloys.

The disadvantages of the liquid metal systems stem from the difficulties associated with accelerating liquid metal to velocities necessary for MHD power generation, i.e., from the process of converting the input thermal energy to the kinetic energy required in the generator. Most liquid metal systems use a vapor to produce this acceleration and either pass a two-phase fluid (liquid and vapor) through the generator or separate the vapor prior to the entrance of the liquid into the generator. A two-fluid liquid metal MHD system using lithium as a circulating working medium and cesium as a gaseous heat transfer fluid has been developed for space application. Other approaches are being examined in laboratories and experimental generators have been demonstrated. One experimental installation of Atomics International is reported to have produced seven kilowatts of sustained self-excited power output at a frequency of 60 H_z.

The liquid metal system has the potential for use with a variety of heat sources but because of the present lack of high temperature nuclear reactors, its use in conjunction with fossil fuel systems is more attractive for central station power generation at this time. Used as a topping unit with a conventional steam cycle the liquid metal system has the potential to improve the overall system efficiency to approximately 45–50 percent and, possibly 55 percent at the upper range of applicable temperatures.

The systems can be coupled directly through a liquid metal boiler or indirectly through an intermediate heat exchanger. It would also be possible to couple the liquid metal MHD system with a high temperature liquid metal fast breeder nuclear reactor and with other reactor systems under development. Though the liquid metal systems offer smaller efficiency increases than open-cycle systems, there appear to be no insurmountable technical obstacles to the development of liquid metal MHD units and a report of the Office of Science and Technology has indicated the system shows sufficient promise for central station power to warrant further investigation. The report recommended that experimental programs involving liquid metal systems for central station power be reestablished at about half the level of support for open-cycle gas systems.

The Electric Research Council, comprising representatives from private and public segments of the electric power industry and created for joint industry financing of engineering research, has recently established a task force to make a major review of MHD technology, keep the council advised of developments in MHD, and recommend specific research where warranted.

Electrogasdynamics (EGD)

The electrogasdynamic generator is a device which, utilizing a moving gas, converts heat energy to electricity by transporting charged particles "uphill" against an electric field. The electric field opposes the flow of a gas containing charged particles. In the process of overcoming this opposition, the electrical potential of the charged particle is increased. The device converts the kinetic energy of the moving gas to high voltage dc electricity by providing an external circuit between a charged particle emitter and collector. The basic generator consists of a non-conducting duct for containing the passage of the gas, a pair of electrodes positioned at the inlet end of the duct to create a supply of charged particles, and an electrode at the outlet end of the duct for "collection" of these charged particles. A simplified diagram of an EGD generator is shown in figure 9.3.

EGD PRINCIPLE

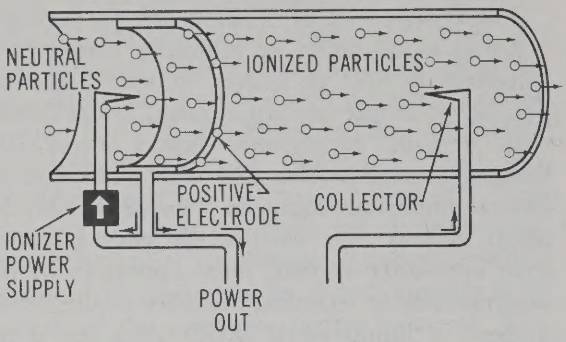


Figure 9.3

Proponents of EGD generation feel that large units can offer considerable benefit in the area of central station power generation while, in a long-range view, smaller units possibly can have application in the area of gas-fueled, on-site power generation. They believe that large EGD generators would require less space and lower capital expenditures than comparable units based on steam-turbine technology, and that the efficiency of energy conversion can equal or better that of present steam-turbine systems. In addition, these generators would require no cooling water and could, therefore, produce power without affecting bodies of water with thermal discharges. The system would also be adaptable to any energy source, such as coal, oil, gas, or nuclear fuel, and could be used to enhance the competitive position of fuels.

The EGD concept has been extensively investigated by research teams at Wright Patterson Air Force Base, Curtiss-Wright of New Jersey, Gourdine Systems, Inc., of Livingston, New Jersey, and at Marks Polarized Corp., in Whitestone, New York. In 1966, Gourdine Systems, Inc., submitted to the Office of Coal Research a proposal for a coal-fired EGD generator and was awarded a contract to engage in the necessary research for the design and test of such a system. A pilot plant was constructed at the Foster Wheeler Research Laboratories in Carteret, New Jersey. Tests on the pilot model uncovered major technical problems and led to termination of the project on September 30, 1968. The original design proved unacceptable because the precipitation of charged particles on the walls of the "slender channel" gas duct resulted in unacceptable energy losses. An evaluation of the Gourdine project made by three scientific entities for the Office of Coal Research indicates that the EGD generator as envisioned by Gourdine Systems, Inc., requires some major breakthroughs before a practical unit can be considered possible.

The Marks Polarized Corporation also recently submitted to the Office of Coal Research a proposal for the development of an EGD generator. The Marks proposal was reviewed by one of the entities which evaluated the Gourdine System and found to be plausible. The need for bench-scale experimental confirmation of projected behavior was deemed necessary before construction of a prototype generator could be considered reasonable but the proposal was said to have considerable promise. Both concerns are seeking funds to proceed with the research activity.

In view of the difficulties encountered in the Gourdine development effort and the relative infancy of the Marks project, it appears unlikely that electrogasdynamics could have a major impact on the electric utility industry prior to the year 1990.

Fusion Reactor

As the name implies, a fusion reactor will utilize a sustained combining, or fusion, of the nuclei of light elements to release nuclear energy and make it available for the production of electricity. Simply stated, the development of a fusion reactor involves the establishment of conditions to produce a fusion reaction and the creation of technologies for harnessing the released energy for conversion into electric power.

There are several known reactions which can be the basis for a controlled fusion reaction. These include deuterium-tritium, deuterium-helium, and two deuterium-deuterium reactions. Much of the interest in the fusion reactor stems from the fact that deuterium is so plentiful and the fusion process can function as a tritium breeder. Also, fusion power may reduce some of the problems associated with nuclear plants, such as siting, licensing, public concern about nuclear hazards, and impact on the environment.

Deuterium is a stable isotope of hydrogen and is found in very low concentrations in all water.

Calculations show that one gallon of ordinary water would yield enough deuterium to equal the energy produced by the combustion of 300 gallons of gasoline. The implication of perfecting a fusion reactor is clear. While the achievement of significant breeding in nuclear fission could provide a source of energy to serve our needs for thousands of years, the nuclear fusion reactor could provide a source of energy that would last for millions of years.

The possibility of accomplishing a fusion reaction has been established by analysis of the energy source of the sun and other stars, and in the explosion of the hydrogen bomb. To date, efforts to develop a controlled fusion reaction, even on a laboratory scale have not been successful. However, several experiments directed toward such a demonstration of technical feasibility are now being conceived, with proposals for them expected to be forthcoming in a matter of months.

For the reaction to occur, it is necessary to raise a fuel to temperatures in the range of 100 million to 1 billion degrees Kelvin; to hold the resultant gaseous dispersion of ions and electrons (plasma) in a configuration which would provide an ion density in the order of 10^{15} ions per cubic centimeter; and to maintain this density for a period of time in the order of tenths of a second. Confinement time, temperature, and density are interrelated, in that shorter confinement times require higher ion densities or temperatures and longer times lower densities. At the same time, fuel must be fed to the system and electrical energy extracted from the developed heat energy.

Many devices have been built throughout the world in attempts to achieve these conditions. On a worldwide basis, over $150 million is being expended annually in fusion research. Japan, France, West Germany, Holland, Sweden, Italy, the United Kingdom, the Soviet Union, and the United States each have programs.

Principal research work is being carried on in the Soviet Union and in the United States. They expend approximately 37 and 20 percent, respectively, of all the money invested throughout the world in controlled thermonuclear research. Efforts in the United States have been carried out in some 40 universities; by several industrial groups, including the utility supported Texas Atomic Energy Research Foundations; and at four major government-supported laboratories—the Los Alamos Scientific Laboratory (LASL), the Lawrence Radiation Laboratory (LRL), the Oak Ridge National Laboratory (ORNL), and the Princeton Plasma Physics Laboratory (PPPL).

Initial fusion research was directed toward establishing a very pure plasma, raising the plasma to thermonuclear temperatures, and adequately confining the plasma. In almost all of the efforts to accomplish these goals, confinement was achieved by magnetic fields. Control of plasma purity and temperature has been accomplished in many experiments and world research efforts are now being concentrated on plasma confinement. The problem of plasma confinement is complicated by the problem of plasma instabilities. These instabilities manifest themselves in diverse ways and generally result in failure of confinement. Many different confinement systems have been tried. These differ in the manner in which the magnetic field is produced, in the resultant magnetic field geometry, in the way the plasmas are established, and in the way plasma temperatures are increased. Though several experiments have achieved one or more of the conditions required for a fusion reaction, none has satisfactorily achieved all three.

Russian accomplishments with the Tokomak T-3 toroidal system are particularly interesting and have been considered as having the best overall performance to date. The British Phoenix II, the American (LASL) Scylla and (LRL) 2X systems have also reached one or more of the fusion criteria and have good overall performance records. Despite this, the American program is presently being revised to take advantage of the Russian accomplishments with the Tokomak T-3 project.

While active researchers are trying to establish a fusion reaction, detailed studies are also made in the United States and the United Kingdom to determine the characteristics of a full-scale fusion power reactor based on the rudimentary state of knowledge available today. A simplified diagram of one type (deuterium-tritium) of fusion reactor power plant is shown in figure 9.4. The design would include a lithium blanket which would act as a neutron moderator and react with nuclear particles to produce

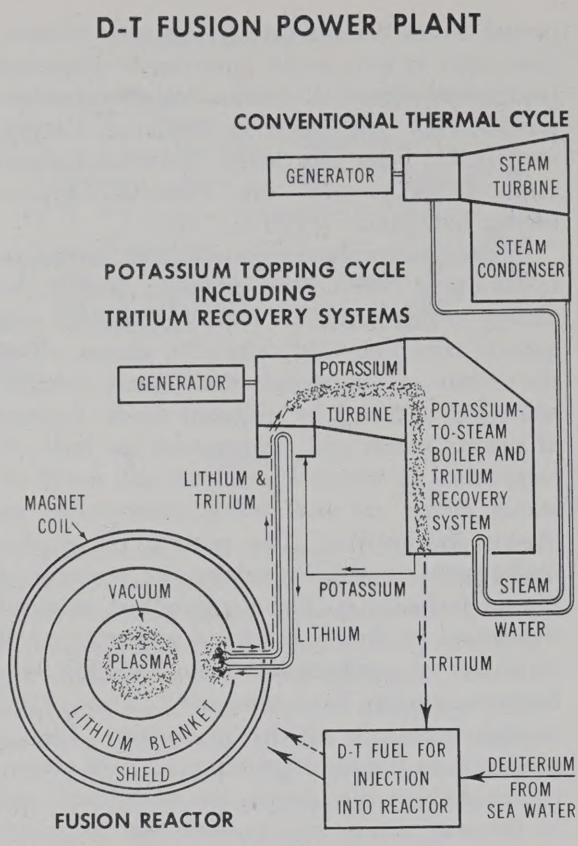


Figure 9.4

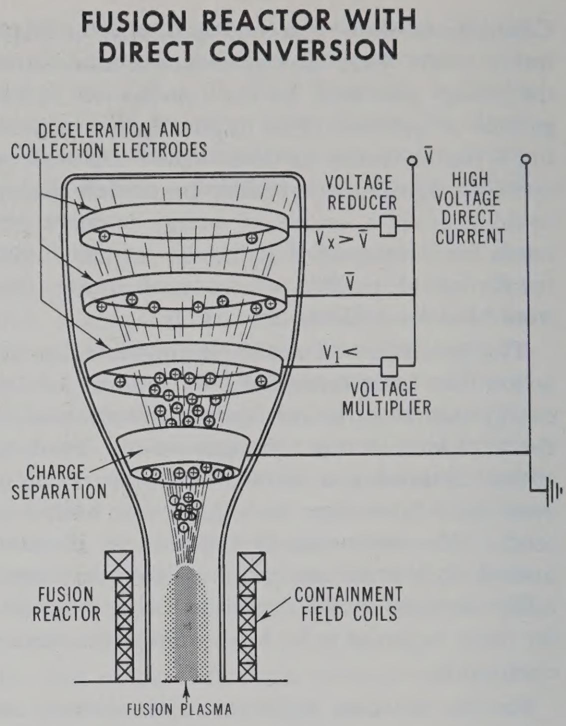


Figure 9.5

tritium. The system would breed more tritium than it would use. The calculated breeding ratio is considerably more than unity and indicates a short doubling time.

The studies have also considered environmental and social factors and suggest that fusion plants would not produce large quantities of radioactive waste, would be inherently safe against nuclear accident, and would have thermal discharges 50 to 70 percent lower than existing plants. In addition to the above, the possibility of direct conversion of fusion energy to electrical energy is also present. This accomplishment would further reduce the environmental impact of the fusion reactor.

The direct energy conversion system illustrated in figure 9.5 is untested but theoretical considerations show possible efficiencies in the order of 90 percent for a 1,000-megawatt unit.[1]

[1] Dr. Glen T. Seaborg, Chairman, U. S. Atomic Energy Commission, at the Council for the Advancement of Science, Writing Seventh Annual Briefing on "New Horizons in Science," Berkeley, California, November 20, 1969.

Small-scale tests of the concept are scheduled for 1971 but direct conversion of fusion energy must still be considered as only a remote possibility.

In addition to power reactors, fusion proponents are also proposing the development of a device referred to as a fusion torch. This concept would use the ultra high temperature fusion plasma to produce large amounts of ultra-violet radiation or to reduce solid materials to their basic elements by means of vaporization. Conversion of the solid material to an ionized gas containing only basic elements would improve the possibility of separation of these elements and the complete utilization of the original material. Such a process is conceived as a means to reduce toxic chemicals, ore, alloys, and waste products to useful elemental materials. The ultra-violet radiation could be used for desalination, bulk heating, waste sterilization, and many other applications. The fusion torch is viewed by those involved with the concept as the one answer to both the technologist and conservationist. Though its realization is unlikely before the turn of the century without a significant increase in support levels, the con-

cept is receiving limited but enthusiastic attention today.

Fuel Cells

Fuel cells are electrochemical devices in which the chemical energy of a fuel, such as hydrogen, is converted continuously and directly to low-voltage direct current electricity. Fuel cells have the same basic elements as the battery; two electrodes, called the anode and cathode, separated by an electrolyte. In contrast to the battery, the fuel cell is an open system which requires a continuous supply of reactants for the production of electricity. The quiet and relatively low temperature operation of fuel cells, and their promise of a highly efficient energy conversion process, have focused considerable interest on them.

One type of fuel cell, shown in figure 9.6, is based on a hydrogen-oxygen reaction. Hydrogen and oxygen are supplied to the anode and cathode, respectively. The hydrogen diffuses through the anode and reacts with the potassium hydroxide electrolyte (KOH) and gives up electrons. These electrons leave the anode and pass through the external load to the oxygen electrode (cathode). The hydrogen ions produced by the surrender of electrons move through the electrolyte to the cathode. At the cathode the hydrogen ions combine with oxygen and the electrons to produce water. In this process the water produced is a by-product and provisions are made for its separation and removal from the electrolyte. Electric current flows through the external load because the anode becomes negatively charged in respect to the cathode.

HYDROGEN-OXYGEN FUEL CELL

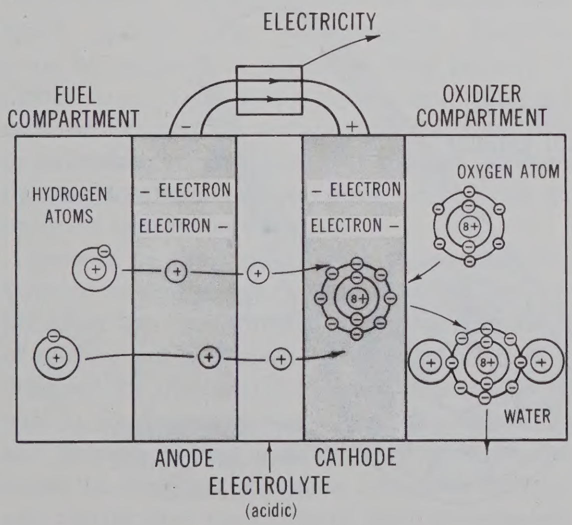


Figure 9.6

Platinum electrodes are utilized in the hydrogen-oxygen fuel cell to speed the chemical reaction. Both hydrogen and the platinum electrodes are very expensive. Although hydrogen-oxygen fuel cells have been used in space and military applications, they are neither available in large commercial sizes nor presently economically competitive with conventional energy sources.

In addition to the hydrogen fueled cells, systems using hydrazine and methyl alcohol have been used. For fuel cells to enjoy widespread use they must use relatively low cost conventional fuels such as coal, natural gas, and petroleum. The present state of the art is such that special processing of these fuels is required before they can be used for fuel cells.

There has been considerable research and development of fuel cells in both the United States and Europe. In Europe a large share of the work has been centered around the molten electrolyte type of fuel cell system. Most of the research in the United States has been aimed toward the development of fuel cells for specialized uses in space and military applications. But a number of programs have been directed toward objectives of primary interest to the power industry.

A strong effort is being made to develop a fuel cell for residential and commercial service. In 1967, a team of 23 natural gas utilities undertook a twenty million dollar, three-year research program to develop a natural gas fuel cell. The team (TARGET—Team to Advance Research for Gas Energy Transformation, Inc.) awarded the contract for the first phase of the program to the Pratt and Whitney Division of United Aircraft Corporation. By 1971 there were 32 TARGET members working in conjunction with Pratt & Whitney and The Institute of Gas Technology. They were at the mid-point of a nine-year research program under which $41,500,000 were to be spent by the end of 1972. One of the early results of this research is the world's first natural gas fuel cell home which was dedicated in Farmington, Connecticut, on May 19, 1971. The research program ultimately will include 37 test installations and a wide va-

riety of residential, commercial, and industrial applications.

The Office of Coal Research has also outlined a program with the Westinghouse Research Laboratory for the development of a fuel cell which uses coal as a fuel, but active research has been temporarily suspended pending the availability of funds.

Fuel cells may be used to store energy during periods of off-peak demand and as generating units during periods of peak demand. In this way, fuel cells could be an alternative to pumped storage projects. Such a converter might also be used for on-site reserve or emergency power supply but would have to compete economically and operationally with internal combustion engines and batteries. Fuel cells are also being considered for use in substations, where they would provide base-load or peaking power to the existing electric power system. This would reduce the need for central station power and transmission lines and consequently reduce the effect of power generation on the environment. An artist's rendition of such a 20-megawatt plant is shown in figure 9.7. The fuel cell holds potential for future use in the transportation field, where batteries are presently used, and in the electrochemical industries where low-voltage dc power is required.

Although the future of the fuel cell is uncertain, it could have a bright future. A successful fuel cell module of 10 to 15 kilowatts, envisioned for single family residences, could be coupled in banks to serve larger users. Looking to the larger applications, the fuel cell, because of its modular capability and the possibility of tailoring power output to a specific customer's needs, could find broad application in industrial, commercial, and apartment complexes. Since many of the fuel cell applications now being actively considered would not be dependent on electric transmission and distribution networks, successful conclusion of the current experiments would permit significant future environmental advantages. The fuel cell is not, however, expected to replace central station power generation.

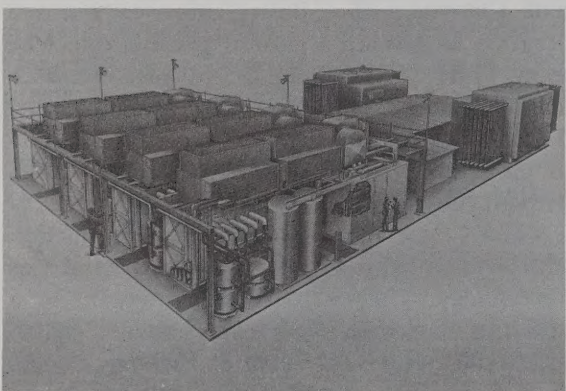


Figure 9.7—Preliminary design rendering of a Pratt & Whitney aircraft 20 megawatt substation fuel cell power plant for operation in parallel with an electric utility distribution system.

Thermionic Generation

When a metal is heated, a point is reached where its electrons acquire enough energy to overcome retarding forces at the surface of the metal and escape. This phenomenon of electron emission, or simply the boiling off of electrons, was discovered in 1878 by Thomas Edison and is the salient feature of the thermionic conversion device shown in figure 9.8.

The simple thermionic generator consists of

THERMIONIC CONVERTER

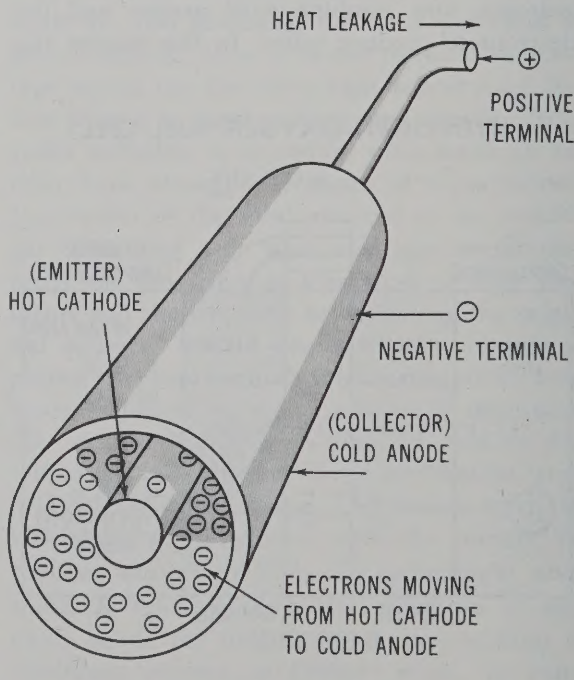


Figure 9.8

two plates, the emitter and collector, separated by a small space. By the addition of heat energy, electrons are freed from the emitter and pass through the intervening space to the collector. This passage of electrons and the electrical properties of the collector enable the development of a voltage difference across the plates. Electric current can then be made to flow through an external load connected between the emitter and collector. The constant application of heat energy provides a constant output of low-voltage direct current electricity.

Thermionic generation is possible with almost any heat source of sufficient temperature, and units have been developed utilizing solar, nuclear, and fossil fuels. In general, thermionic development has been oriented toward space activities, with relatively little effort being concentrated on central station power development.

Units have operated satisfactorily at relatively low power levels and efficiencies for thousands of hours, but many problems hinder economic application in the commercial power market. Present reports show conversion efficiencies of 15 to 25 percent and power densities as high as 50 watts/cm² but these for the most part are laboratory accomplishments. Maximum obtainable efficiency is limited to the Carnot efficiency of an ideal heat engine operating between inlet and exhaust temperatures which correspond to the emitter and collector temperatures. The emitter temperature required for efficient operation ranges between 2500 and 3200°F. At these temperatures, major problems are encountered which prevent long life operation. Emitters must be designed to withstand long periods of operation at high temperatures, and collectors must be designed to withstand degradation due to oxidation. In addition, heat transfer between the emitter and collector must be reduced to optimize conversion efficiency.

Because of the high emitter temperature requirements of thermionic generation, considerable effort has been directed toward development of nuclear powered units. Generators have been designed for use outside the core of a reactor as well as for incorporation within the reactor itself (in-pile). These activities have been concentrated in the space programs and both isotopic and reactor heat sources have been investigated. The problems encountered in using the reactor are generally in the interface between the heat source and the generator. They involve the material fabrication of generator elements and the development of a heat pipe, or coupling, between the heat source and generator. The in-pile concept introduces the additional problem of fabricating generator components which must also function as fuel elements in the nuclear reactor heat source.

Isotopic heat source thermionic diodes have achieved 10,000 hours of operation at efficiencies in the order of 12 percent at temperature ranges between 2500 and 3000°F. Developed heat pipes have also experienced satisfactory operation in excess of 10,000 hours. In general, little activity has been directed toward the development of nuclear reactor-fired thermionic generators for central station power generation. Reactor manufacturers have been considering the possibility of thermionic topping units but to date no appreciable effort has been expended in this direction.

The Office of Coal Research has a two-phase program directed toward the development of thermionic converters as topping devices for fossil-fueled steam-powered central station power plants.

One phase of the study showed that, for a specific plant studied, thermionic topping could increase the plant capacity and efficiency more than 20 percent. The second phase of the program involved an experimental and material effort to establish the guidelines for fabricating the thermionic converters and plant. Converters have been operated in a coal-fired environment for as long as 85 hours at power levels in the order of 112 watts but a viable thermionic module design suitable for testing a small-scale coal-fired system is still being sought.

Research activities in all phases of thermionic generation have been taking place in many countries throughout the world, and some projects have passed from the research stage to the development phase. German concerns have embarked on a six-year $50 million program for the development of a reactor-fueled thermionic generator-powered television satellite. The United Kingdom, Russia, and Belgium also have thermionic projects. A number of concerns in the United States have participated in the development of commercial applications for thermionic generation. One such project, under the

sponsorship of the American Gas Association, was directed toward developing a 300-watt gas-fired unit to power the fan of a home gas furnace.

Thermionic devices fired by propane and gasoline have also been investigated. Under partial sponsorship of the Department of Defense, this project has been aimed at the development of units in sizes up to 10 kilowatts. It is expected that these units would be more expensive than engine-generators but that a demand for the thermionic units could develop in the mobile or semiportable power supply market. Federal budgetary restrictions and project technical difficulties have led to the termination of these programs, and little is being done today in the development of commercial thermionic devices.

The consensus is that future efforts in thermionic development during the next decade will be concentrated in space-oriented activities. The principal effort will be directed toward the development of nuclear-fueled systems to be used as power sources for interplanetary expeditions. There is small likelihood of thermionics achieving commercial realization for large scale generation within the next several decades.

Thermoelectric Generation

The thermoelectric generator, shown in figure 9.9, is a device which converts heat energy directly into low-voltage direct current electricity. It makes use of the 100-year old "Seebeck principle," that a voltage difference is produced between the ends of two joined dissimilar conductors when heat is applied. With advancements in the technology of semiconductor materials it became possible to produce usable generating units. Usable amounts of electric power are produced by connecting several generating units into thermopiles for use as a single generator. It is also possible, by varying the materials used for thermoelectric conductors, to operate the generators in different segments of a wide range of operating temperatures.

The maximum efficiencies possible using this method of generation are limited to that of an ideal heat engine operating between inlet and exhaust temperatures which correspond to the hot and cold junction temperatures.

With possible efficiencies in generator technology in the order of 30 percent, it appears that overall efficiencies of thermoelectric systems can-

THERMOELECTRIC CONVERTER

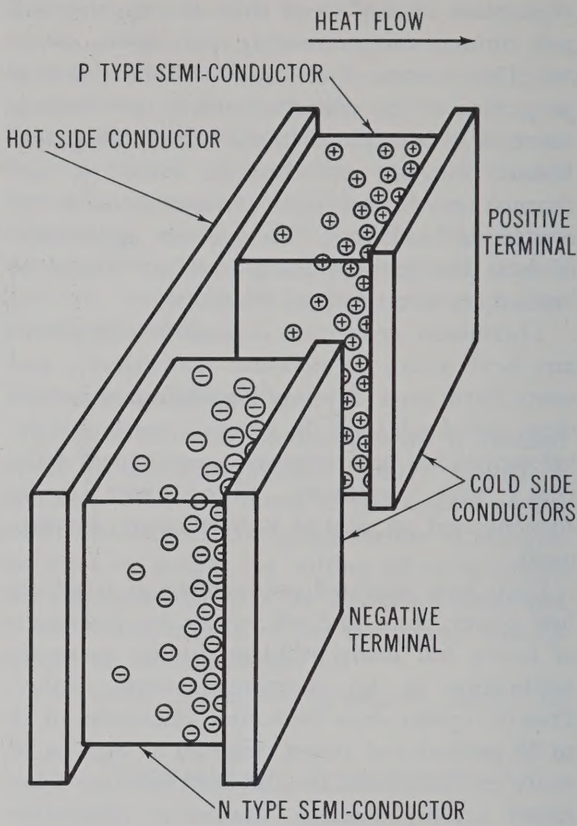


Figure 9.9

not exceed 10 to 15 percent. Efforts are being made to increase the internal efficiency of the process but the rate of progress has tapered off. Although there are intensive materials research programs, further advancements are becoming more expensive and time-consuming. Short operating lifetimes, which result from the instability of thermoelectric elements at the high temperatures necessary for higher power operation, and undesirable heat transfer from the hot to cold junctions, which results in low efficiencies, are major obstacles to additional progress.

Thermoelectric generators have been built which utilize solar, fossil-fueled, and nuclear heat sources. These units have been operated successfully in space and military applications and in remote areas. In the first successful attempts using solar heat sources, thermoelectric power was produced at efficiencies of 1 to 3 percent. Since then, series generators have produced power at efficiencies exceeding 5 percent. Bell

Laboratories is experimenting with a generator which operates at a power level of 160 watts and an efficiency of 2 percent. This unit is used as a power source for communications equipment in remote areas.

Although thermoelectric generation will doubtless receive continued attention for special low power applications, it would seem to hold little promise for central station power plants in the foreseeable future.

Geothermal Generation

Geothermal generation uses natural steam or hot water entrapped below the surface of the earth's crust to produce electrical power. The steam or hot water is released from the earth's depths through holes bored into the interior. The steam or water made available by "tapping the pocket" is piped to a generating facility nearby. The process takes advantage of the many "hot spots", such as geysers, hot springs, and fumaroles, on the earth's surface. These hot spots are seen to be features of the worldwide system of oceanic ridges, continental rifts and associated zones of earthquake activity, volcanic eruption, and other geothermal activity. One such geothermal belt extends from South America north through Central America, Mexico, and along the western United States to Alaska, west and south through the Aleutians, Japan, Taiwan, and the Philippines. A second belt exists in the northern Mediterranean and passes through Italy, Greece, Turkey, the Near East, and into the Indian Ocean. The Pacific belt encompasses roughly 86 million acres of land in the western United States which may have geothermal resources. The California geyser area alone is already estimated to have a capability of producing 2½ million kilowatts and its boundaries or total reserves are not yet fully known. One New Zealand geothermal reservoir has been estimated to contain 10,000 trillion pounds of high-pressure steam.

Geothermal fields are broadly classified as fumarole fields and hot spring or geyser fields. In the former, wells at the surface produce slightly superheated steam, while the latter produce boiling water at the surface with only small quantities flashing into steam. Although geothermal steam is more commonly used, hot geothermal water may be used to produce electrical power. This has been done in New Zealand and Japan and will be done shortly in Mexico. Two processes are available. In one, hot water is introduced into a flash tank where steam is produced by dropping the water pressure. This steam is used to drive a turbine-generator. Hot water can also be used to evaporate a low boiling point fluid such as butane or freon which can be used as the working fluid in a turbine. The technology for locating and developing these fields is still being refined. Initial approaches were similar to the geological techniques used early in the location of oil but, with deep drilling techniques and new prospecting tools, geologists are beginning to develop more productive approaches.

The potential of geothermal energy was first recognized in Italy in 1904. Italian engineers drilled a shallow well in a fumarole field in northern Italy and used the released steam to supply a small turbine. Under government auspices, the Italian engineers then developed techniques for controlling steam wells to generate power and over the years have expanded the capacity of the site to 300 megawatts. In the early 1950's New Zealand began developing a geyser area at Wairakei and by the late 1950's was producing up to 200 megawatts of geothermal power. This was the first plant drawing on a hot-water field and led to the development of other smaller plants in Japan, Mexico, and the Soviet Union. In the United States, geothermal ventures were initiated in 1955, and in 1960 a 12.5 megawatt generating unit delivered power produced by geothermal steam. A second plant was put in operation in 1963, and the addition of two more units brought the total geothermal capacity of 84.2 megawatts in 1968. The Pacific Gas and Electric Company, which pioneered the development of this resource in the United States, expects to have over 600 megawatts of such capacity by the end of 1975.

Geothermal enthusiasts foresee future installations involving deep drilling through the earth's mantle (20–30 miles) making it possible to tap energy sources almost anywhere on earth. They also envision producing high-pressure steam by the injection and recirculation of water through huge subterranean hot cavities or reservoirs created by underground nuclear explosions. This procedure is also expected to provide a slurry of metal ores suitable for additional processing and

marketing. Experiments in recirculation techniques have already been initiated. Overall, however, geothermal generation is not expected to become a significant factor in central station generation in most sections of the country.

The Geothermal Steam Act of 1970,[2] authorized the Secretary of the Interior to issue leases for the development and utilization of geothermal steam and associated geothermal resources on public, withdrawn, and acquired lands administered by him or administered by the Department of Agriculture through the Forest Service. The Act specifies the terms and conditions under which the leases are to be granted.

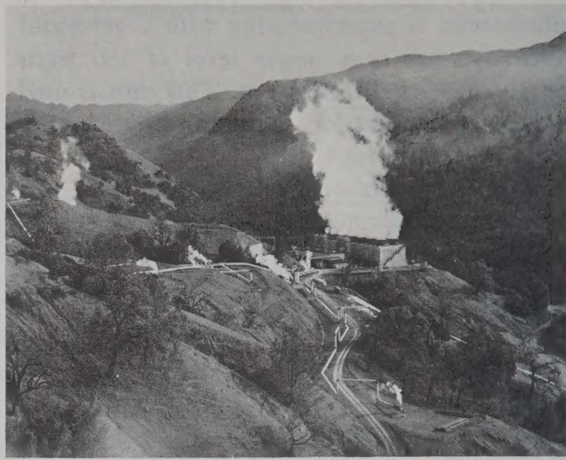


Figure 9.10—"The Geysers," Pacific Gas and Electric Company's geothermal plant in Sonoma County, California, is the only such plant in North America. The four existing units have a combined capacity of 84 megawatts. Two additional units expected to be in operation in 1971 will raise the total plant capacity to 203 megawatts. Steam leaves the well heads at about 350 degrees Fahrenheit and is piped to the turbines after cleaning. One of the unique aspects of the operation is that makeup water for the cooling tower is supplied from condensed geothermal steam.

Solar Generation

Power from the sun is not new. As early as 1901, energy from the sun was used to provide power for a steam engine. Since then solar energy has been used to power many devices. Its use for the most part was restricted to latitudes between 40 degrees north and 40 degrees south and to applications which were not sensitive to its discontinuous nature. Such things as solar water heating plants and solar distillation plants have been functioning satisfactorily for years. By 1966, Israeli scientists had developed a solar-powered electric generating plant which incorporated a mirror collector and a heat storage system enabling night operation at reduced load. The most successful application of solar energy to date has taken place in the space programs. The use of solar heat sources to power thermoelectric and thermionic conversion devices was a factor in the successful completion of several space programs. Based on the technology available today, the economics of solar generation are questionable except for space usage and other equally unique applications.

Two uses for solar energy which are being considered today involve the establishment of major power generating facilities. One concept suggests development of floating power plants that will utilize the solar-produced temperature differential which exists between the upper and lower levels of Caribbean waters and the Gulf Stream. The higher temperature upper levels and colder lower levels have been suggested for use as a heat source and heat sink to produce up to 100 megawatts of electric power. A second concept deals with the orbiting of space vehicles for the purpose of creating central station power generation.

The efficiencies and cost-weight characteristics of existing solar conversion devices place them in an unfavorable economic position today. However, recent discoveries of organic compounds possessing semiconductor and photovoltaic properties, together with theoretical and experimental data, indicate the organic compounds may provide conversion devices with high efficiency and low cost-weight ratios. Successful development of such devices would make the possibility of orbital power stations more nearly feasible. In this concept, solar stations orbiting the earth would collect solar energy from the sun's rays and convert the solar energy to electric energy for electric microwave transmission to earth. The design problems include a number of separate areas such as orbital characteristics, conversion devices, transmission facilities, and the reception of power on earth.

At this time, the development of orbital solar collection stations for central station power generation appears to be within the projected capa-

[2] PL 91-581, approved December 24, 1970, 84 Stat. 1566.

bilities of system engineering and would not require the discovery of any new physical principles. However, the necessary development efforts, the possible excessive costs of the resultant technology, and unknowns such as reliability and harmful effects on the environment would preclude application of such systems in the foreseeable future.

CHAPTER 10

DISPOSAL OF WASTE HEAT FROM STEAM-ELECTRIC PLANTS

Introduction

Currently, more than 80 percent of the electric energy produced in the United States is generated by steam-electric plants. Even considering the results of the research now under way to develop new means of energy conversion, it seems likely that for the foreseeable future the bulk of electric generation will depend upon nuclear and fossil-fueled steam-electric plants.

At the exhaust of a steam-electric plant turbine, the steam is condensed to water to maximize the energy conversion and then is returned to the boiler or reactor for a repetition of the cycle. A large amount of heat is rejected in the condensing process. Even at the most efficient plants now in operation, the heat rejected is substantially greater than the heat equivalent of the electric energy generated.

All waste heat from steam-electric plants must eventually be dissipated to the atmosphere. Some heat is transferred directly to the ambient air and, in the case of fossil-fueled plants, some heat is discharged up the stacks. However, the bulk of the waste heat is transferred from the steam to the cooling water in the condensers. Water is used as the absorbent because of its general abundance, its high specific heat, and its ability to dissipate heat in the evaporation process.

Waste heat discharged to water bodies contributes to physical and biological changes and constitutes a potential polluting agent. Growing concerns for environmental protection and the State and Federal regulations stemming from such concerns are increasingly requiring the use of cooling systems that reduce or eliminate the discharge of waste heat to water bodies. Measures can be taken to protect adequately the quality of water bodies but the overall results of such measures will be greater consumptive use of water, increased capital and operating costs of steam-electric plants, and decreased plant capabilities and efficiencies.

Large amounts of water are used for cooling and condensing purposes by major industries such as primary metals, chemical and allied products, and petroleum and coal. However, electric power production currently accounts for more than four-fifths of the total cooling water used in the United States. It also accounts for nearly one-third of the total water withdrawn for all purposes.

Types of Cooling

In passing through the condenser of a steam-electric plant, the cooling water is heated 10 to 30 degrees Fahrenheit, depending upon plant design. The waste heat added to the cooling water may then be dissipated to the atmosphere in several ways. Where the cooling water is returned to a natural water body, the ultimate dissipation of heat is accomplished by evaporation, radiation, and conduction. If the heat is dissipated in a wet-type cooling tower, it is accomplished principally by the evaporation of some of the water. In a dry-type cooling tower, the heat dissipation is almost entirely by conduction and convection.

The principal types of cooling systems now in use or proposed for steam-electric plants are:

(1) once-through using fresh or saline water,
(2) cooling ponds, including spray ponds,
(3) wet cooling towers, and
(4) dry cooling towers.

In some cases a combination of systems may be used. The water withdrawal requirement varies widely among these systems.

Once-Through Cooling

With a once-through cooling system, water is taken from a suitable source, passed through the

condenser, and then returned to the source body of water. Such systems have generally been used where there were adequate supplies of water and no resulting adverse effects on water quality were expected. Normally, once-through cooling is more economical than other systems and, in most cases, affords higher plant thermal efficiency.

Rivers have been used extensively as sources of cooling water. The flows of streams have provided a natural conveyance for waste heat discharges. In view of the magnitude of flows required to dissipate the waste heat from the large steam-electric plants projected for the future, and the possible adverse effects of the heated discharges on the water quality, it appears that the number of river sites suitable for new once-through cooling installations will be limited.

When rivers are used to provide water for cooling purposes, the heated water discharges may exceed 100° F. during summer months, although the water temperatures are rapidly reduced by mixing with the receiving waters. Without proper dispersion, however, the discharges could be harmful to aquatic life and objectionable for recreation and other water uses. One way of obtaining dispersion is by discharging the heated water into the main channel of the stream through multiple outlets such as is done at the Hanford nuclear plant on the Columbia River and is planned for the Browns Ferry nuclear plant on the Tennessee River. See figure 10.1. Another disperson method is to release the heated water through a discharge jet, which induces rapid mixing.

Where available, large lakes or reservoirs may be used as sources of cooling water, provided that such use would not violate water quality standards or be incompatible with other planned uses of these water bodies. An important consideration in designing cooling systems using lakes or reservoirs is the separation of the intake and discharge lines. Such separation may be accomplished by using separate arms of the water body for intake and discharge, by constructing dikes or canals, or by other means. Vertical separation may be achieved by the use of skimmer devices and submerged dams.

The thermal stratification of some reservoirs during summer months provides a potential source of low-temperature cooling water. During winter months, reservoirs are usually isothermal, i.e., they have about the same temperatures from the top to bottom layers. In the spring the reservoirs become stratified into three temperature layers. As indicated in figure 10.2, the upper layer, or epilimnion, is warmed by the sun and mixed by the wind, resulting in a relatively high and constant temperature in the top few feet of the water body. The second layer, or metalimnion, is a transition zone in which the temperature drops sharply. In the third layer, or hypolimnion, extending to the bottom of the reservoir, there is only a minor change of temperature with depth and the temperature is only slightly higher in summer than that prevailing during the winter.

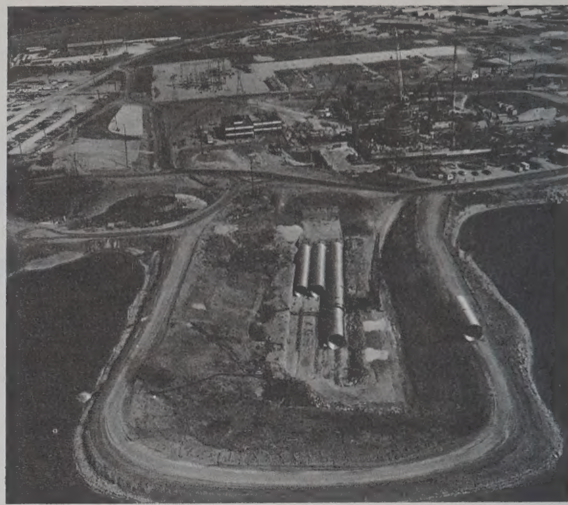


Figure 10.1—The heated water from TVA's 3,500-megawatt Browns Ferry nuclear power plant, which is under construction on Wheeler Lake in northern Alabama, is dispersed through three diffuser pipes, 17, 19, and 20.5 feet in diameter and of different lengths. The last 600 feet of each pipe is perforated on the downstream side with holes two inches in diameter.

In several installations, cooling water has been taken from the hypolimnion and the heated water released to the epilimnion with little or no increase in the surface temperature of the reservoir. An example is the Marshall steam-electric plant on Lake Norman in North Carolina.

A disadvantage of such a scheme is that the water in the hypolimnion tends to become low in dissolved oxygen as the summer progresses. Thus, discharge of these waters to the surface tends to lower the oxygen content of the epilim-

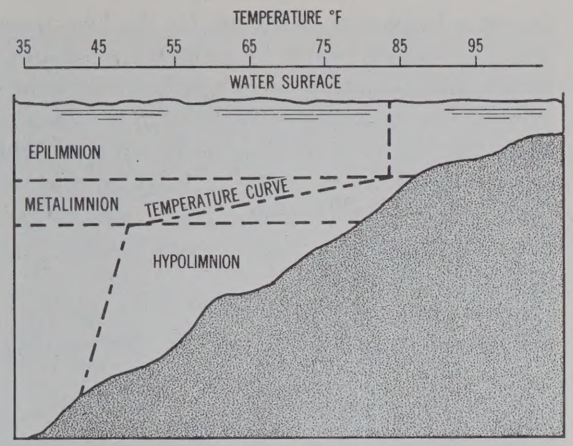


Figure 10.2—Typical thermal stratification of reservoirs during summer months.

nion. However, in the epilimnion the water would be mixed with water relatively high in oxygen and, furthermore, it would be reaerated at the surface due to wind and wave action and to circulation induced by the cooling water discharges and by diurnal heating and cooling. Pumping water from the hypolimnion would reduce its volume, thus tending to reduce the time during late summer when cool water could be released for downstream uses. If the cool water discharges support a downstream cold water fishery, the early depletion of the hypolimnion could adversely affect the fish. However, in impoundments where low oxygen levels in the hypolimnion could adversely affect downstream users, there may be advantages in promoting destratification. Use of a reservoir so as to change its pattern of stratification would require careful attention to effects on the ecology of the reservoir.

Some steam-electric plants utilize estuarine water for cooling purposes. However, there usually are temperature restrictions which tend to limit the number of sites available for such uses. There is increasing awareness of the value of estuaries for growing shellfish and as breeding areas for ocean fisheries, a large proportion of which are dependent upon estuaries in some way. This value of estuaries may limit or preclude their use for power plant siting, and in any case appears likely to impose needs for special measures to minimize harmful effects.

A large potential source of cooling water for once-through systems is the ocean. Coastal locations are commonly used in Britain, Sweden, Japan, the United States, and elsewhere. In only a few instances has marine life been observed to have been adversely affected by coastal thermal plants using ocean water for cooling purposes. Where exceptions have occurred, the effects could have been limited had the intake and discharge points been properly selected. Beneficial effects, such as increased fishing, have occurred at some existing plants.

The intakes and outfalls of coastal plants should be located so as to avoid the entrainment and destruction of fish eggs, larvae, or fish, and to avoid raising temperatures to a degree and at locations that would interfere with significant amounts of fish spawning or migration. This would generally require the selection of plant sites where currents would not bring the heated effluent to shore areas. It may also be necessary to construct long intake and discharge lines, including screens for the intakes.

For cooling water systems using either estuarine or ocean water, the condensers must be constructed of expensive corrosion-resistant metals. In some cases, stainless steel or nickel base alloys are used.

Cooling Ponds

Where suitable sites are available on streams with insufficient flow for once-through systems, cooling ponds may be constructed to provide cooling water. Water would be recirculated between the condenser and the pond. Sufficient inflow would be needed, either from upstream runoff or by diversion from another stream, to replace the evaporation induced by the addition of heat to the pond and to control the buildup of minerals in the cooling water (figure 10.3). A pond surface area of one to two acres per megawatt of plant capacity, combined with adequate pond depth, may be required, depending upon the type of plant and such factors as the local weather and wind conditions, and the configuration of the pond surface. The cooling capacity of a pond may be increased by spraying the warm water into the air over the pond surface (figure 10.4). Cooling ponds are frequently used for other purposes such as sources of municipal water supply and for recreational uses.

Wet Cooling Towers

Where availability of water and water quality standards preclude the use of surface waters for

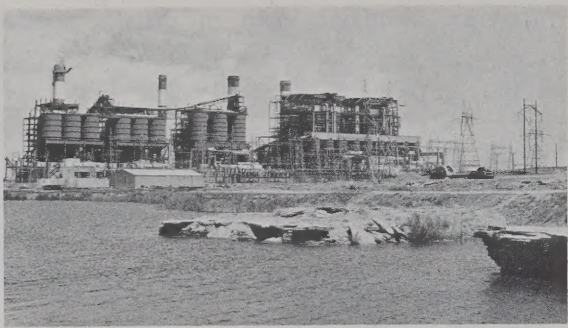


Figure 10.3—The 1,200-acre cooling pond for Arizona Public Service Company's 2,085 megawatt Four Corners power plant, near Farmington, New Mexico, receives make-up water from the San Juan River.

once-through cooling and suitable sites for cooling ponds are not available, cooling towers are generally employed for the dissipation of waste heat. Cooling towers may be used to provide full cooling requirements, to provide full cooling only during certain periods of the year, or to provide partial cooling during certain periods or throughout the year.

In wet cooling towers, the warm water is brought in direct contact with a flow of air and the heat is dissipated principally by evaporation. The warm water is distributed at the top of a dispersal section, called "fill," that is generally made of cement asbestos, treated fir or redwood, or plastic material such as polyvinylchloride. The fill may be of the splash type or film type. The splash type fill breaks the water into droplets that subdivide as they descend, thereby exposing large surface areas to the air for the evaporative heat transfer. The film type fill allows the water to descend as a thin film so as to expose a large area to the air for the heat transfer. The cooled water is collected in a basin under the fill section from which it is pumped back to the condenser to pick up more heat and then is returned to the cooling tower. The limit of cooling of warm water is fixed by the wet bulb temperature. The flow of air may be provided by either mechanical means or natural draft.

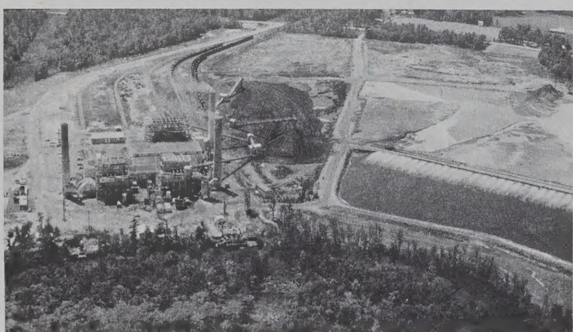


Figure 10.4—Spray pond is used at South Carolina Electric & Gas Company's 490-megawatt Canady station on the Edisto River.

Small droplets of water may be carried from the towers by the cooling air. This spray is generally called "drift" or "carryover." Drift losses sometimes are reduced by an arrangement of louvers between the fill and the air outlet of the tower.

Solids from the dissolved chemicals in the source water accumulate in the circulating cooling water, as a result of evaporation, and must be periodically or continuously removed by "blowdown." Make-up water must be added to replenish the losses due to evaporation, drift, and blowdown. The added water may require chemical treatment to protect the fill from deterioration, to prevent the spray nozzles from clogging, or to protect the condenser tubes from corrosion. It is also necessary to assure appropriate sustained flows and acceptable water quality in the stream from which the cooling water supply is drawn and to which the blowdown is released. In water-deficient areas, sewage treatment plant effluents have been used in some cases to provide the make-up requirements (figure 10.5). Where used, some additional treatment of the effluents may be required.

Mechanical Draft Towers

Until recently all cooling towers constructed in this country for steam-electric plants were of the mechanical-draft type shown in figure 10.6. Such towers are usually designed for induced draft with the fans in the air outlets. The induced draft towers may be designed for counterflow providing for an upward flow of air to meet the downward flow of the water (figure 10.7), or crossflow, with a horizontal air flow meeting the downward water flow (figure 10.8).

Fans in mechanical draft towers provide positive control over the air supply and thus permit substantial control over the temperature of the cooled water. However, the towers may be subject to recirculation of the hot, humid air from the exhaust to the air intakes, and when this oc-

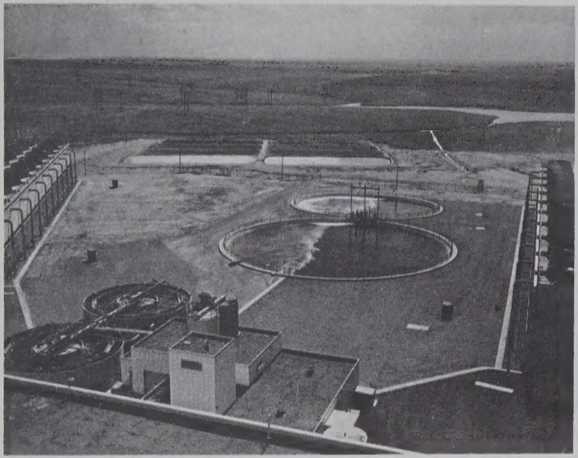


Figure 10.5—Southwestern Public Service Company's 435-megawatt Nichols plant, located near Amarillo, Texas, uses the effluent from a municipal sewage treatment plant as its source of cooling water. The water treatment building with the lime storage tanks on the roof and the cold lime reactors are shown in the left foreground; the two lagoons to store the water until it is needed are in the center; and the two cooling towers are shown at the extreme right and left. The blowdown from the towers is discharged into the pond shown in the background for irrigation on an adjoining farm.

curs, the plant efficiency is reduced. Also, the humid exhaust air may, in some cases, cause localized icing and fogging problems.

Natural Draft Towers

Although long used extensively in Europe, natural-draft cooling towers did not come into use in the United States until 1962. Since that time, a number of natural draft towers have been constructed or planned. These installations include large hyperbolic towers designed to create a flow of air by means of the chimney effect caused by the difference in density of the internal and external air. The density of the internal air is lowered as it comes into contact with the warm water. Since the dispersion of the heated effluent is dependent in part upon the velocity of the wind, the towers should be located in unobstructed areas. A counterflow arrangement may be used whereby the fill is placed inside the tower near ground level so that the falling warm water can meet the rising air and facilitate evaporative cooling; or a crossflow arrangement may be used whereby the fill is located around the periphery of the shell and the warm

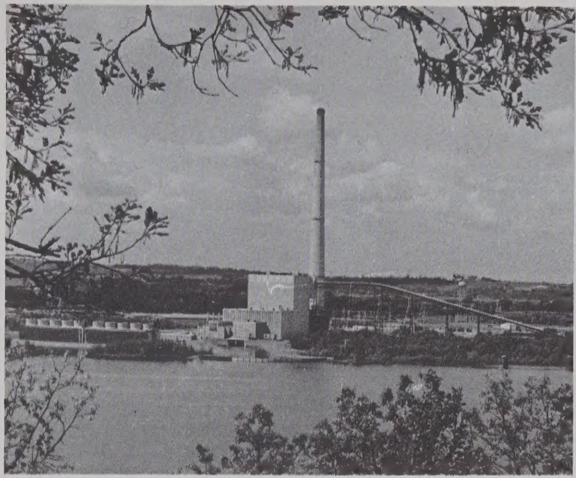


Figure 10.6—Northern States Power Company's 580-megawatt Allen S. King plant on the St. Croix River uses mechanical draft towers, shown at left, to reduce the cooling water temperature before releasing the water into the lake.

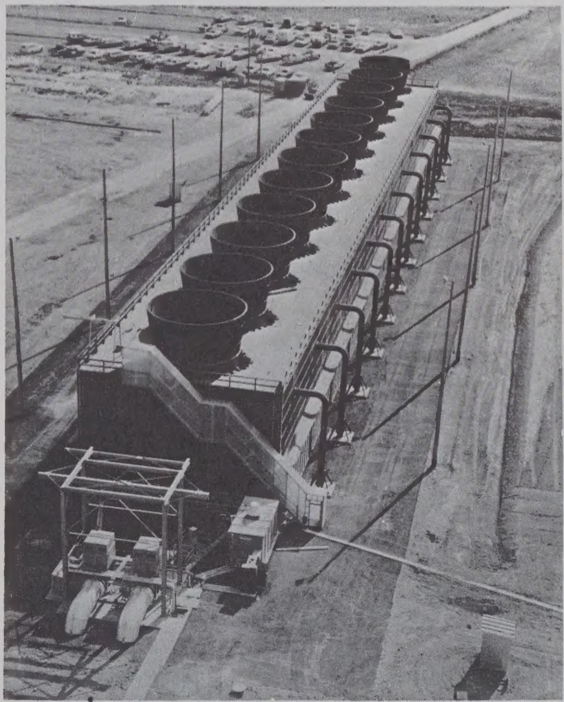


Figure 10.7—An induced draft, counterflow cooling tower is used at the Utah Power and Light Company's 200-megawatt Naughton No. 2 Unit, located near Kemmerer, Wyoming. The approximate dimensions of the cooling structure are: length 360 feet, width 48 feet, and height 31 feet.

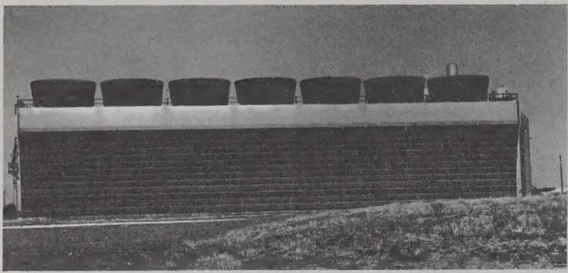


Figure 10.8—An induced draft, crossflow cooling tower provides cooling for Western Farmers Electric Cooperatives' 125-megawatt Mooreland No. 2 Unit, located in western Oklahoma.

water falls through the horizontally moving air. Natural draft towers now being constructed are 400 feet or more in height and 400 feet or more in diameter at the base. Figure 10.9 shows a typical installation.

Natural draft towers are less likely than mechanical draft towers to be affected by the recirculation of air from the exhaust to the air intakes. Because of their height, the likelihood of ground-level fogging and icing problems in the vicinity of hyperbolic towers is small. However, where towers are placed near exposed roads, hills, or other obstructions, problems can develop if not considered at the time of design. Care should also be taken in locating the cooling towers at fossil-fueled plants to minimize the mixing of moist air and stack gases.

Natural draft towers have a high capital cost as compared to mechanical draft towers, but the

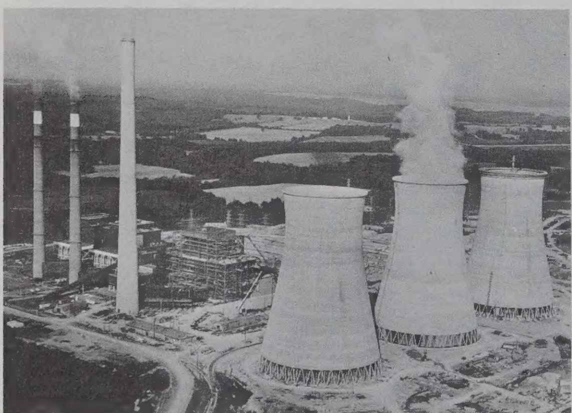


Figure 10.9—Three cooling towers are used at TVA's 1,400-megawatt Paradise Steam Plant in western Kentucky to supplement the cooling capacity of the Green River. Each tower is large enough at the base to cover a football field and is 437 feet high.

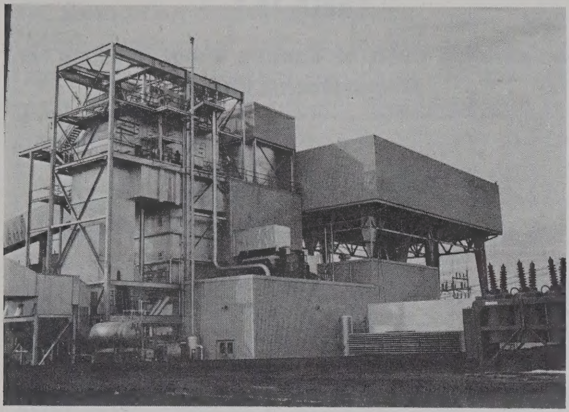
latter have higher operation and maintenance expenses because of the moving parts and the power required to drive the fans.

Dry Cooling Towers

In "dry" or "air" cooling systems, the heat is dissipated to the air by conduction and convection in a heat exchange system analagous to an automobile radiator. Thus, there are no evaporative losses of water with subsequent make-up requirements, but much greater air movement is necessary to absorb the heat. The cooling temperatures achievable in dry-type towers are limited by the dry bulb rather than the wet bulb air temperature with the result that higher turbine exhaust temperatures, and higher condenser back-pressure will be experienced. This could place a severe penalty upon the efficiency and capability of the power plant. In most cases, the loss in capacity would occur during very warm weather when loads are highest. In cold climates, problems of freeze-up during periods of plant shutdown or partial operation may cause operating difficulties.

There are two basic types of air-cooled condensing systems. In the direct system, the turbine exhaust steam is conveyed through large-diameter ducts to the cooling facility where headers distribute the steam to sections of finned tubes. A flow of air, usually provided by large fans, passes over the tubes and condenses the steam. The cooled condensate is then returned to the boiler feedwater circuit. A number of cooling systems of this type have recently been constructed, mostly in Europe and generally serving plants with relatively small installations. However, a 160-megawatt plant in Spain is reported to use direct-type dry cooling. As shown in figure 10.10, direct dry cooling is utilized by a 20-megawatt unit recently completed in Wyoming. A similar type facility for a 3-megawatt unit was constructed in the same area in 1962.

Indirect dry cooling, generally referred to as the Heller system, is illustrated in figure 10.11. This system utilizes a direct contact condenser into which the cooled water is sprayed to mix with and condense the exhaust steam. Some of the warm water from the condenser goes to the boiler feedwater circuit, but most of it is pumped to a dry-type tower for cooling. The flow of air over the cooling coils may be pro-



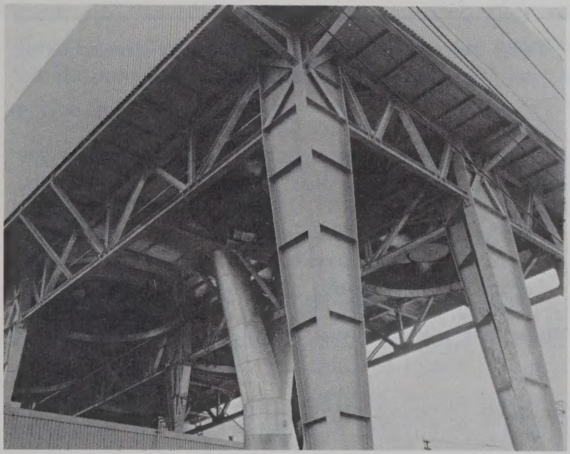


Figure 10.10—Air cooled condensing is used by Black Hills Power and Light Company's 20-megawatt unit in the Neil Simpson station near Gillette, Wyoming. Exhaust steam enters a header which feeds sections of finned-tubes where it is condensed and cooled. Air is forced over the tube sections by six fans, each 18 feet in diameter.

vided either by fans or by natural draft. The cooled water is recirculated to the condenser to repeat the cycle. Several plants using indirect dry cooling have been constructed, mostly in Europe. An installation of this type utilizing a natural draft cooling tower was constructed at Rugeley, England in 1962 to service a 120-megawatt unit. A similar installation was completed in 1971 to service a 200-megawatt unit at the Grootvei plant in South Africa. The principal difference between direct and indirect dry cooling systems is the large volume of exhaust steam which must be handled in the direct system, compared to the smaller volume of circulating water in the indirect system. Consequently, the direct-type system may be limited to generating unit sizes of 200 to 300 megawatts, whereas the indirect type may be provided for unit sizes of 1,000 megawatts and larger.

Because of the large surface area required for heat transfer and the large volumes of air that must be circulated, dry cooling towers are substantially larger and more expensive than evaporative towers. However, in arid regions there is need for cooling systems that do not make consumptive use of water, so further investigation and development of dry cooling towers is desirable and should be given high priority.

Cost of Cooling Water Systems

The costs of various types of cooling systems depend upon the design criteria and the site conditions. Ranges of costs have been developed from data supplied by a number of electric utility systems. Although both higher and lower costs have been quoted, the ranges developed are believed to be reasonable. It should be noted that only two small dry-type cooling towers have been constructed in the United States.

Ranges of estimated investment costs of cooling water systems are summarized in table 10.1. The costs cover such items as pumps, piping, canals, ducts, intake and discharge structures,

INDIRECT DRY (HELLER) COOLING SYSTEM

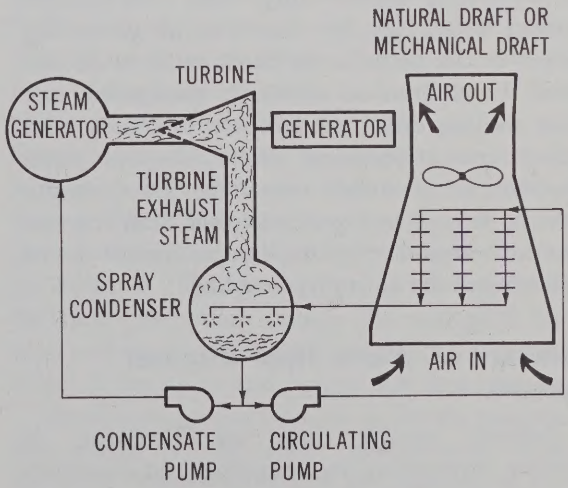


Figure 10.11

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dams and dikes, reservoirs, cooling towers, and appurtenant equipment. The costs of condensers and auxiliaries have been excluded. The cost estimates for cooling ponds are predicated on the availability of sites with relatively low costs for lands and relocations.

An operating expense common to all cooling systems is the cost of power needed to pump the water through the systems. In most cases, cooling towers would have pumping heads in the range of 35 to 55 feet greater than those required in once-through systems. The added pumping power for evaporative towers would be equivalent to one-half percent or more of the plant output. Power to drive the fans in mechanical draft evaporative cooling towers would be equivalent to as much as one percent of the plant output. Annual operation and maintenance expenses, except for pumping costs, are relatively small for once-through systems. For cooling tower systems, annual operation and maintenance expenses, exclusive of costs of power for pumping and to drive fans, are equivalent to one to two percent or more of the investment cost of the cooling systems.

The use of evaporative cooling towers rather than once-through systems could increase the cost at the plant of generating power by as much as five percent or more. Also, the higher water temperature at the condenser inlet that would normally result from the use of cooling towers would produce a lower turbine efficiency. Most estimates indicate a one percent capacity penalty chargeable against plants using wet cooling towers. Some estimates indicate that the use of dry-cooling towers rather than once-through systems could increase the cost of generating power at the plant by as much as 20 to 25 percent. Thus, from an economic standpoint, dry-type cooling does not compare favorably with other types at locations where adequate water supplies are available. Also, the plant output may be from 6 to 8 percent lower than the output with once-through cooling because of the efficiency penalty of dry-type cooling.

Esthetics of Waste Heat Disposal Systems

Esthetic considerations are becoming of greater importance in designing and constructing structural improvements. In addition to the efforts to improve the quality of the air and of water courses, steps are being taken to maintain and protect the natural beauty of the general environment. In general, the esthetic impact of various methods of waste heat disposal are inversely proportional to the cost of the system. Chapter 12 includes a discussion of esthetic considerations involving waste heat disposal systems.

TABLE 10.1

Comparative Costs of Cooling Water Systems for Steam-Electric Plants

Type of System	Investment Cost, $/kW [1]	
	Fossil-Fueled Plant [2]	Nuclear-Fueled Plant [2] [3]
Once through [4]	2.00–3.00	3.00–5.00
Cooling ponds [5]	4.00–6.00	6.00–9.00
Evaporative cooling towers:		
Mechanical draft	5.00–8.00	8.00–11.00
Natural draft	6.00–9.00	9.00–13.00
Non-evaporative cooling towers:		
Mechanical draft	18.00–20.00	26.00–28.00
Natural draft	20.00–24.00	28.00–32.00

[1] These investment costs represent ranges derived as of the year 1969. Future construction costs will probably be higher.

[2] Based on unit sizes of 600 MW and larger.

[3] For light water reactor plants. High temperature gas cooled, liquid metal cooled, or molten salt reactor plants, same as fossil fueled.

[4] Circulation from lake, stream, or sea and involving no investment in pond or reservoir.

[5] Artificial impoundments designed to dissipate entire heat load to environment. Cost data are for ponds capable of handling 1,200–2,000 MW of generating capacity.

Effects of Thermal Discharges on Ecology

All discharges of heated water will contribute to physical and biological changes in the receiving body. These changes can be beneficial, detrimental, or insignificant depending upon the ecology of the particular water body, the desired uses of that body, and the amount and temperature of the discharges. When the discharge of heated cooling water produces effects that are detrimental to other desired uses of water, it can be said that "thermal pollution" has occurred. Thermal pollution is significantly differ-

ent from other forms of pollution, since, unlike chemical wastes or sewage, it does not involve the addition of foreign matter to the environment and the heat is usually dissipated into the atmosphere rather quickly. The addition of heat to water bodies, however, may increase rates of chemical solubility and biochemical reactions, causing effects on aquatic organisms in the area of higher temperatures. Thus, the addition of heat to a water body can alter the aquatic environment unfavorably and heat may then be regarded as a potential polluting agent.

Although much has been learned regarding the control of this recently recognized pollution problem, there are still large gaps in the available knowledge. Following is a discussion of some of the effects of thermal discharges on water, the effects of such discharges on aquatic life and water uses, and possible beneficial uses of the thermal discharges.

Effects on Water

The capacity of water to hold dissolved oxygen is decreased with an increase in temperature. This oxygen-carrying capacity is usually expressed as the saturation level. Thus, the dissolved oxygen concentration at saturation is less at elevated temperatures than at lower temperatures. For example, raising the water temperature from 55 to 68 degrees F. results in a loss of approximately 13 percent in the oxygen-carrying capacity (saturation level) of the water. Studies at some existing power plants with once-through cooling indicate that despite the adverse effects suggested by theoretical and laboratory studies, heating of the water by the power plants does not cause a change in the dissolved oxygen content of the water in passing through the condensers. The saturation level may be changed but, inasmuch as few natural waters used for cooling purposes exist at saturation, the effect is negligible.

The addition of heat to a water body can cause stratification because of the reduced density of the water at increased temperatures. The difference in density with a relatively few degrees difference in temperature is often sufficient to cause the waters to flow as separate and distinct layers. Thus, heated water discharged to the surface of a water body tends to spread out and remain on the surface. Cooling water taken from the hypolimnion of a reservoir and discharged after use at a temperature lower than that of the surface may move as an interflow below the surface layer.

Effects on Aquatic Life

Water provides the environment for many species of organisms, and changes in its temperature, chemical content, and rate of flow may affect the kinds and numbers of such organisms in a given water body. The increasing demands for larger cooling water supplies for steam-electric plants have resulted in a number of studies of the effects of thermal discharges on aquatic life. However, predictions as to the effects of both temperature changes and maximum temperatures still cannot be made with certainty, especially if the changes are gradual, are not far from ambient temperatures, and occur for only a short time, or affect limited areas or volumes of large water bodies. The ability of ecosystems to adapt to or to recover from partial changes is a major consideration.

Temperature changes normally play an important and highly regulatory role in the growth of aquatic plants and in the growth and physiology of fish and other cold-blooded aquatic animals. Reproductive cycles, digestive rates, respiration rates, and other processes occurring in the bodies of aquatic animals are often temperature dependent. These effects are not consistent among species, however, so thermal constraints are among the most difficult to define and establish. It is known that temperatures higher than those normally experienced, particularly during summer months, can be detrimental in a variety of ways. The survival of individual organisms can be jeopardized; they may be more susceptible to disease or to the effects of toxic agents; their food supply or their ability to catch food may diminish; and the inability to reproduce or to compete successfully with other organisms may indirectly eliminate a species. There may also be unpredictable synergistic effects, related to dissolved heavy metals for example. The elimination of one species in the food chain may change the ecological balance and cause significant changes in the composition of the plant and animal life that remains.

All aquatic species have an optimum temperature range. If the water temperature varies above or below this range the chances of survival for a particular species decrease. Rapid

change in temperature caused by thermal plant start-up and shut-down can be lethal to organisms in the affected area, although adult fish generally have the ability to avoid undesirable temperatures. For some aquatic species the effect produced by the warming of initially cold water could be beneficial. But the chances of survival of this same species would be progressively diminished if the temperature is further increased, especially if the change is rapid. Since different species favor different temperatures, a warming trend may lead to the population decline of one species and the growth of another.

Studies indicate that oxygen consumption of aquatic vertebrates increases with rises in temperature up to a limiting temperature beyond which the physical exchange of oxygen in the blood is no longer possible. This increased need for oxygen is coupled with the decreased ability of the water to hold oxygen at higher temperatures.

Changes in temperature can cause certain gases dissolved in the water to change their selective toxicity toward fish. Studies show that low concentrations of carbon dioxide can be lethal above certain temperatures. An increase in the temperature of water saturated with nitrogen may result in the water becoming supersaturated. As supersaturation increases, the nitrogen dissolved in the water more easily changes to the gaseous state and forms bubbles. Such conditions can be lethal to salmonoid and other fish. This special problem may occur in segments of the Columbia River when dams release stored waters which have been supersaturated with nitrogen. Corrective measures are being taken.

Thermal discharges when properly controlled have resulted in an increase in the ability of certain commercially valuable aquatic species to multiply, while at the same time decreasing the time for the species to reach maturity. Experience has shown that in a number of plant locations the discharge of waste heat to a stream or reservoir has improved fishing in the vicinity of the discharge during the cooler months of the year.

The use of water for cooling purposes at steam-electric plants may have effects on aquatic organisms other than those resulting from thermal discharges. The effects of passing fish and their larvae or eggs through pumps and condensers may indicate the need for screening intakes, preferably with traveling screens having little or no impingement velocity. Some organisms too small to screen may be affected by the high condenser temperatures as well as increased pressure and velocity resulting from entrainment and passage through the condenser tubes. Chemicals used intermittently for defouling the condensers could adversely affect fish and fish food organisms.

Effects on Water Uses

Although some uses of water bodies are not affected by changes in temperature, other uses may be affected either beneficially or adversely. Among the uses of fresh waters that are affected by heat discharged in cooling water from steam-electric plants are those for public water supplies and organic waste disposal. Some industrial uses may also be affected if the water is heated.

Chemical reactions tend to proceed at a faster rate as water temperatures rise. This could reduce the amount of chemicals required for the treatment of public water supplies. It has been estimated that the resulting savings would range from 30 to 50 cents per million gallons of water treated for each 10 deg. F. rise in temperature. On the other hand, increases in summer water temperatures make drinking water less palatable and tend to push algal populations in the direction of a greater proportion of blue-green algae. Some blue-green algae are notorious for producing tastes and odors in water supply systems, again affecting palatability.

Temperature is a major factor in determining the organic waste assimilation capacity of a water body. The water temperature plays a triple role, affecting the rate of oxidation of pollutants, the capacity of the water to hold oxygen in solution, and the rate of reaeration of the water. The net effect of adding heat to a stream may be a lowering of its capacity for satisfactorily assimilating organic wastes.

Possible Beneficial Uses of Waste Heat

In winter, adding heat to a river could be beneficial if the added heat prevents ice and light-excluding snow covers from forming. Also, reaeration could take place in the open water areas below thermal discharges.

Studies are under way to find other feasible ways of utilizing waste heat from steam-electric

plants. Pertinent research needs are discussed in chapter 21. It appears unlikely, however, that practicable uses for significant amounts of the available waste heat will be found in the near future. A 1,000-megawatt steam plant requires about a billion gallons a day of cooling water, but under the most extreme condition the discharge water temperatures will be less than human body temperatures. Uses will therefore be limited, but could include such things as industrial processing, improvements in irrigation agriculture, and advances in aquaculture. Recognition is also being given to the use of cooling ponds for recreational purposes. The water might be used for space heating, but its thermal qualities are too low-grade for such use to be economically attractive. Similarly, very few industrial processes can effectively use energy of such low quality.

Agriculture is a potential user of waste heat. Irrigation with heated water could promote faster seed germination and growth and extend the growing season. Hothouses could be used to grow tropical or subtropical crops in the more temperate regions of the country. However, a number of problems need to be solved before large-scale use of heated water for irrigation could become common practice. Also, the effects of plant shut-down on such uses of warm water need to be explored.

Another potential use of condenser discharge water is aquaculture. Marine and freshwater organisms may be cultured and grown in channels or ponds fed with heated water. For example, it may be possible to grow commercially valuable oysters in areas where they cannot normally reproduce or survive due to low water temperatures. Studies are being made of the possibility of increasing lobster production in Maine with the use of waste heat. Consideration is being given in the Puget Sound region of Washington State to the use of warm water to promote the spawning and growth of oysters, crabs, and mussels. Proposals have been made in Wisconsin to use waste heat to warm sport fish hatchery waters and increase growth rates.

The Long Island Lighting Company has an arrangement with a local oyster company which allows its Northport plant's cooling water discharge basin to be used for oyster production. Preliminary tests have shown that both oysters and hard-shelled clams not only survive but have exceptional growth in the cooling water. The water, which passes through stainless steel cooling jackets, is not only non-toxic to the young shellfish but also supports a luxuriant growth of microscopic algae, possibly because it is drawn from a deep section of Long Island Sound and has a high nutrient content. Thus, not only may the young oysters be grown in winter, but the lagoon may prove to be a much more satisfactory environment for seed oyster production throughout the year. The Long Island installation is shown in figure 10.12.

An experimental installation has been made by a private company at the Gallatin steam-electric plant of the Tennessee Valley Authority to determine how much increase in production will result from growing catfish in warm condenser discharges, compared to production of catfish in unheated river water. If the results of the experimental installation are as expected, the entrepreneur plans to install a commercial-sized installation. The Texas Electric Service Company has conducted successful experiments of catfish culture in the cooling water discharge canal at its Morgan Creek plant.

The warm waters of cooling ponds can provide important recreational areas. Lands adjacent to the 2,600-acre Lake Sangchris are being developed by the State of Illinois for recreational use. In addition to fishing, facilities are to be provided for boating, camping, and picnicking. This lake was created by Commonwealth Edison Company to provide a source of cooling water for its 1,200-megawatt Kincaid generating station. The cooling pond for Virginia Electric and Power Company's 1,140-megawatt Mt. Storm plant is used for boating and

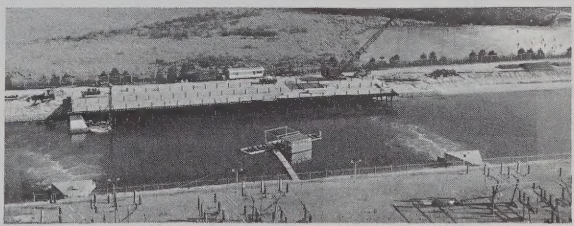

Figure 10.12—The cooling water discharge basin for Long Island Lighting Company's Northport plant on Long Island Sound will include an oyster hatchery and marine museum facility, the foundation of which is shown on the far bank. An experimental nursery installation is shown near the center of the basin.

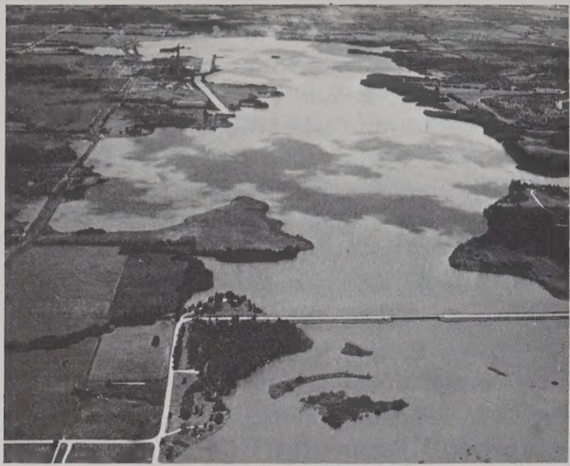

Figure 10.13—Kansas City Power & Light Company's Montrose Lake provides cooling water for its 563-megawatt Montrose power plant and is available for camping, fishing, boating, and waterfowl hunting.

water skiing. Kansas City Power & Light Company placed its Montrose Lake under the jurisdiction of the Missouri Conservation Commission which maintains facilities for various types of recreation. Figure 10.13 is an overall view of this impoundment.

Figure 10.14 shows some of the possibilities in the use of cooling ponds for various recreational and residential purposes. However, care must be exercised in selecting the types of uses, to avoid those uses contributing significantly to the eutrophication process of the pond and adversely affecting its usefulness for cooling purposes.

State and Federal Regulation of Water Quality

Various State and Federal laws for regulating the quality of water bodies may affect the location and design of steam-electric plants. Principal Federal statutes include the Water Quality Act of 1965, the Water Quality Improvement Act of 1970, and the implementation of provisions of the 1899 Refuse Act. Also, the Federal Power Commission has some responsibility for water quality regulation where steam-electric plants utilize lands and waters of licensed hydroelectric developments.

Water Quality Act of 1965

Although water quality standards had previously been adopted by some States and interstate bodies, a major impetus was given to the establishment and enforcement of such standards when the Federal Water Pollution Control Act was amended by the Water Quality Act of

Figure 10.14—Possible multiple uses of a cooling lake.

1965.[1] Under that statute, the States were authorized to establish, within guidelines developed by the Secretary of the Interior, water quality standards for interstate streams, including coastal waters, and to submit these for approval as Federal standards by the Secretary, or, after the governmental reorganization of December 2, 1970, by the Administrator of the Environmental Protection Agency.[2] If the States fail to submit acceptable standards, the Administrator is authorized to establish such standards.

The Act requires that the standards be such as to protect the public health or welfare and enhance the quality of water. In establishing the standards, consideration is to be given to the use and value of water for public water supplies, propagation of fish and wildlife, recreational purposes, and agricultural, industrial, and other legitimate uses.

As intepreted by the Environmental Protection Agency, the standards to be established include water use classifications, criteria necessary to support uses under the respective classifications, and a plan for implementation and enforcement. The criteria include the physical, chemical, or biological characteristics needed by aquatic life, industrial processes, or other intended uses. For streams expected to have more than one use, the criteria of the most sensitive use would be governing in establishing the standards. In most cases the criteria applicable to fish and other aquatic life would be controlling, although domestic water supply would be an important factor in some areas.

As an aid in reviewing proposed water quality standards, the Secretary of the Interior, who was then responsible for administering the Water Quality Act, appointed a National Technical Advisory Committee on Water Quality Standards. The Committee's report, published in 1968, recommended criteria in five general areas of water use. In considering uses by fish and other aquatic life, the Committee discussed various temperature requirements. It concluded that, in view of the many variables, no single temperature standard could be applied to the country as a whole, or even to one State.

As a general guide, the Committee recommended that, during any month of the year, heat should not be added to a stream in excess of the amount that would raise the temperature of the water (at the expected minimum daily flow for that month) more than 5 deg. F. In lakes and reservoirs the temperatures of the epilimnion should not be raised more than 3 deg. F. above that which existed before the addition of the heat of artificial origin. Unless a special study showed that a discharge of heated effluent into the hypolimnion or pumping water from the hypolimnion (for discharging back into the same water body) would be desirable, such practice was not recommended. For estuarine areas, the monthly means of the maximum daily temperatures recorded at a site before the addition of heat should not be raised more than 4 deg. F. during fall, winter, and spring, or by more than 1.5 deg. F. in summer. Inland trout streams, headwaters of salmon streams, trout and salmon lakes and reservoirs containing salmonids, should not be warmed. Also, no heated effluents should be discharged in the vicinity of spawning areas.

The Committee recognized the need for mixing areas but stressed the essential requirement that adequate passageways be provided at all times for the movement or drift of the biota in the water body. It noted that the shape and size of mixing areas would vary with the location, size, character, and use of the receiving water and should be established by proper administrative authority.

The temperature criteria in water quality standards proposed by the States are to be established on the basis of the proposed uses of the water bodies. Generally, maximum permissible temperature and maximum changes in temperature constitute the criteria. Some States have specified maximum rates of change in temperature. Several State standards provide for varied criteria depending upon the season of the year. Some waters are so designated as to allow no change from the natural conditions. In such cases, the limitations are usually determined by the requirements of fisheries.

Most States have established 68 deg. F. as the maximum allowable temperature and from 0 to 5 deg. F. as the maximum allowable change in temperature for streams with cold water fisheries. For warm water fisheries, the maximum al-

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[1] PL 89–234, approved October 2, 1965, 33 U.S.C. § 1151 et seq. (1970).

[2] Chapter 11 summarizes the provisions of the reorganization plan, as related to EPA.

lowable temperatures are generally in the range of 83 to 93 deg. F. Some States have proposed higher temperature rises, but these generally have not been approved by the Environmental Protection Agency. Some States have specifically defined the limits of mixing zones while others have not.

Many States have adopted as part of their standards the nondegradation statement previously formulated by the Secretary of the Interior. This statement provides that waters with quality above that provided for in the approved standards will not be permitted to be degraded below the present quality level. Exceptions to this policy in specific instances could be proposed by the States, subject to Federal approval.

It should be recognized that the proposed and approved temperature criteria are not necessarily established permanently. On the basis of experience, changes may be proposed by the States or the Environmental Protection Agency and approved by the Administrator. It should be noted also that, in addition to the criteria for interstate and coastal waters, many States have established standards for intrastate waters.

The Federal Water Pollution Control Act, as amended, declares it to be the policy of Congress to recognize, preserve, and protect the primary responsibilities and rights of the States in preventing and controlling water pollution. Consistent with that policy declaration, the Act provides that State and interstate action to abate pollution of interstate or navigable waters shall be encouraged and shall not, except as otherwise provided by or pursuant to court order, be displaced by Federal enforcement action. The Act provides, also, that the discharge of matter into interstate waters, or portions thereof, which reduces the quality of such waters below the approved water quality standards is subject to abatement in accordance with Federal procedures set forth in the Act.

The Federal procedures to abate pollution, which is or may be occurring, provide for the Environmental Protection Agency, under conditions outlined in the Act, to convene abatement conferences, call public hearings, and take other enforcement actions. If, after such proceedings, satisfactory actions are not taken, the Administrator may request the Attorney General to bring suit to secure abatement of the pollution, including thermal pollution.

The Act provides that the court shall receive in evidence the prior record of the proceedings and receive such further evidence as the court deems proper. The court, "giving due consideration to the practicability and to the physical and economic feasibility of securing abatement of any pollution proved, shall have jurisdiction to enter such judgment, and orders enforcing such judgment, as the public interest and the equities of the case may require".

Water Quality Improvement Act of 1970

The Water Quality Improvement Act of 1970,[3] a further amendment of the Federal Water Pollution Control Act, provides that an applicant for a Federal license or permit to conduct any activity which might result in any discharge into the navigable waters of the United States must provide to the licensing agency a certification from the State or appropriate interstate agency, that there is reasonable assurance that such activity will be conducted in a manner which will not violate applicable water quality standards.

In cases where the standards have been promulgated by the Environmental Protection Agency, or where the State or interstate agency does not have authority to give the certification, such certification shall be from the Administrator. For any application for license that was pending on the date of approval of the Act and for which license was issued within one year of the enactment date, the certification must be furnished within one year of the issuance of the license. Where actual construction of the facility was under way on the date of approval of the Act, the certification must be provided within three years of the enactment date.

Refuse Act of 1899

The 1899 Refuse Act[4] provides that it is unlawful to discharge refuse matter into navigable waters of the United States or their tributaries. The Act provides further that the Secretary of the Army, whenever the Chief of Engineers determines that anchorage and navigation will not be injured thereby, may issue permits for the deposits of material into navigable waters.

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[3] PL 91–224, approved April 3, 1970, 33 U.S.C.A. § 1171 (1971).

[4] Section 13 of the Act approved March 3, 1899, 33 U.S.C. § 407 (1970).

These provisions of law have been little used in the past. However, by Executive Order [5] the President has directed the executive branch of the Federal Government to implement a permit program under the Refuse Act to regulate the discharge of pollutants and other refuse matter into navigable waters of the United States or their tributaries. One of the authorizations relied upon in undertaking this program is a provision in the National Environmental Policy Act of 1969 directing that, to the fullest extent possible, policies, regulations, and public laws of the United States be interpreted and administered in accordance with the environmental protection policies set forth in that Act.

Regulations governing operation of the permit program were published on April 7, 1971. The program is administered by the Corps of Engineers. Under the regulations, permits are required for all direct and indirect discharges or deposits (except those flowing from streets and sewers) by any person, firm, or other entity into a navigable waterway or tributary. Water discharged into a navigable waterway or tributary at a temperature different from that of the receiving water is considered to be a discharge or deposit to which the Refuse Act is applicable.

Decisions as to whether, or on what conditions, a permit under the Refuse Act may be granted are to be based on an evaluation of the impact which the discharge or deposit may have on (1) anchorage and navigation, as determined by the Corps of Engineers; (2) applicable water quality standards and related water quality considerations, as determined by the Environmental Protection Agency; and (3) fish and wildlife values not reflected in or adequately protected by applicable water quality standards, based on recommendations of the Secretaries of the Interior and Commerce. No permit would be issued in cases where an applicant is required but fails to obtain a State or other appropriate certification under the Water Quality Improvement Act of 1970, that the discharge or deposit will not violate applicable water quality standards. Permits would normally be subject to revalidation at the expiration of five years. However, a permit of longer duration and subject to such revalidation provisions as the Corps of Engineers may consider appropriate may be issued with the approval of the Environmental Protection Agency.

[5] Executive Order 11574, issued December 23, 1970.

Enforcement of the permit program may involve the institution of either civil or criminal actions by the Department of Justice under the Refuse Act, or the initiation of administrative proceedings to suspend or revoke the permits.

Other Regulatory Authorities

In addition to having primary responsibility for enforcing water quality standards and for granting certificates covering compliance of proposed facilities with applicable water quality standards, some States now consider, and others are instituting arrangements for considering, thermal effects in granting certificates for power plant construction.

In cases where steam-electric plants make use of lands and waters of non-federal hydroelectric developments licensed by the Federal Power Commission, the Commission may include provisions in the hydroelectric licenses regulating such use by the steam-electric plants, including use of the waters for cooling. The Commission has determined (40 FPC 522) that, in the interest of protecting and developing the fishery resources affected by a project, it can require compliance with water quality standards, including thermal criteria, more stringent than those approved for use by the States. In formulating license conditions, the FPC obtains the views and recommendations of appropriate State and Federal agencies. The Commission may require operational studies to assure compliance with, or need for meeting more stringent, water quality standards.

By Order No. 412, issued October 22, 1970, the Commission required electric utilities to report steam-electric plant air and water quality control data on a new FPC Form 67. The order required an initial filing for 1969 and annual reports thereafter. Required information includes for each steam-electric plant, data on cooling water system designs, capital and annual costs of cooling operations, water use data, temperature measurements, and amounts and costs of chemicals used in cooling operations.

Analyses of Cooling Systems for Projected Steam-Electric Plants

Analyses were made of the possible cooling systems of steam-electric plants projected to be

in operation in 1980 and 1990 in order to indicate the probable impacts on the nation's water resources and the range of effects on power costs. The analyses were made on a plant-by-plant basis but considered only plants with installations of 500 megawatts or more. Plants of this size constitute approximately 75 percent of the total steam-electric capacity in 1970, 90 percent of the projected steam-electric capacity in 1980, and 97 percent of that projected for 1990.

Basis of Analyses

Analyses were made of the possible types of condenser cooling, sources of cooling water, water uses, and cooling water costs for steam-electric plants projected to be in operation in 1980 and 1990. Recognizing the lack of sufficient information to make long-range predictions of the possible impacts of thermal criteria on cooling water designs, the studies were made on the basis of three alternative assumptions. The results indicate the possible range of impacts on water resources and on the cost of power production.

Study A was made on the assumption that compliance with thermal criteria comparable to those suggested by the National Technical Advisory Committee would adequately protect the quality of water bodies. This would include the use of properly designed mixing zones of carefully delineated, limited areas. However, no site would be considered available for once-through cooling use until thorough biological and other relevant studies had been completed and the projected effects were shown to be within acceptable limits. Provisions would need to be made for post-operation monitoring studies. Under Study A, a once-through cooling system was selected for each plant where conditions appeared favorable for meeting the above requirements. Possible sources of cooling water included rivers, lakes, reservoirs, and estuaries. At some coastal locations, ocean outfalls were selected. At sites where conditions did not appear favorable for meeting the above requirements, and where sufficient land area appeared to be available, cooling ponds were selected. For sites where land for cooling ponds was not available, evaporative cooling towers were selected. In making this study, supplemental cooling facilities were selected in all cases where there was doubt that the protective requirements stated above could be met. The following temperature rises, after mixing of the condenser discharges, were selected:

Streams with cold water fisheries	2°F.
Streams with warm water fisheries	5°F.
Estuaries—summer months	1.5°F.
Estuaries—winter months	4°F.

Study B was made on the assumption that the thermal criteria suggested by the National Technical Advisory Committee, including appropriate mixing zones, would prove to be inadequate for protecting the quality of water bodies. Thus, each plant or plant addition constructed after 1970 would be expected to require a cooling pond or an evaporative cooling tower unless it could utilize water from the ocean, with a long outfall.

Study C was made on the assumption that each plant operating in 1980 and 1990, regardless of when constructed, would be expected to require a cooling pond or an evaporative cooling tower unless it could utilize water from the ocean, with a long outfall. This would require the backfitting of plants constructed without such facilities.

Table 10.2 shows the basis for estimating the cooling water requirements.

Although no dry cooling towers were selected in the analyses, it appears likely that such installations will be made at some sites during the next 20 years. It is believed, however, that the number will not be sufficiently large to affect appreciably the results of the analyses.

Impacts on Water Resources

Table 10.3 summarizes the estimated national water uses for steam-electric power plant cooling under 1970 conditions and under Studies A, B, and C. As shown in the table, the fresh water withdrawals in 1990 under Study A would be almost three times the 1970 withdrawals but such withdrawals under Study C would be only one-seventh of the 1970 withdrawals. However, the consumptive use of fresh water in 1990 would be seven times the 1970 amount under Study A but 10 times the 1970 amount under Study C. The 14,700 cubic feet per second estimated to be consumed in 1990 under Study C is equivalent to the average annual runoff at the mouth of the Potomac River. It is equal to nearly one percent of the average annual runoff of all rivers in the conterminous United States. However, one per-

TABLE 10.2

Estimated Cooling Water Requirements for 1,000-Megawatt Steam-Electric Plant Operating at Full Load

Type of Plant	Plant Heat Rate [1] Btu/kWh	Condenser Flows-cfs For Various Temperature Rises Across the Condenser			Consumptive Use, cfs For Various Types of Cooling		
		10° F	15° F	20° F	Once Through	Cooling Ponds [2]	Cooling Towers [3]
Fossil (1980)	9,500	2,080	1,390	1,040	12	16	28
Fossil (1990)	9,000	1,890	1,260	950	10	14	26
Nuclear (1980)	10,500	2,920	1,950	1,460	17	22	40
Nuclear (1990)	10,000	2,710	1,810	1,360	15	20	35

[1] For fossil-fueled plants in operation in 1970, a heat rate of 10,000 Btu per kWh and a temperature rise of 13° F were assumed, except where reported heat rate data were available.

[2] Where appropriate, an additional allowance was made for natural evaporation from the pond surface.

[3] Evaporative towers; includes blowdown and drift.

cent of a river's mean annual flow could amount to 15 to 20 percent of its low monthly flow in humid regions and substantially higher percentages in arid regions.

Figure 10.15 shows the estimated water uses for cooling purposes for each of the six National Power Survey regions.

Effects on Power Costs

Table 10.4 shows for the nation the estimated capital costs of cooling facilities, and the related annual and per-kilowatt-hour costs, under conditions existing in 1970 and under the three studies for 1980 and 1990. As shown in the table, the cooling facilities expected to be in operation in 1990 under Study A would have a capital cost of $6.3 billion and an annual cost of $1.3 billion compared to a capital cost of $9.8 billion and an annual cost of nearly $2.0 billion under Study C. The resulting average cooling costs per kilowatt-hour of electric energy estimated to be generated by thermal plants in 1990 would be 0.24 mill under Study A compared to 0.37 mill under Study C. These may be compared with the estimated unit cost under existing conditions of 0.15 mill per kilowatt-hour. None of these estimates include allowances for the financial or economic cost of the water.

Figure 10.16 shows the estimated capital and annual costs for cooling facilities for each of the National Power Survey regions.

Overall Impacts

The overall impacts of cooling water use by steam-electric plants on water resources and on power costs cannot now be projected with assur-

TABLE 10.3

Estimated National Water Use for Steam-Electric Power Plant Cooling

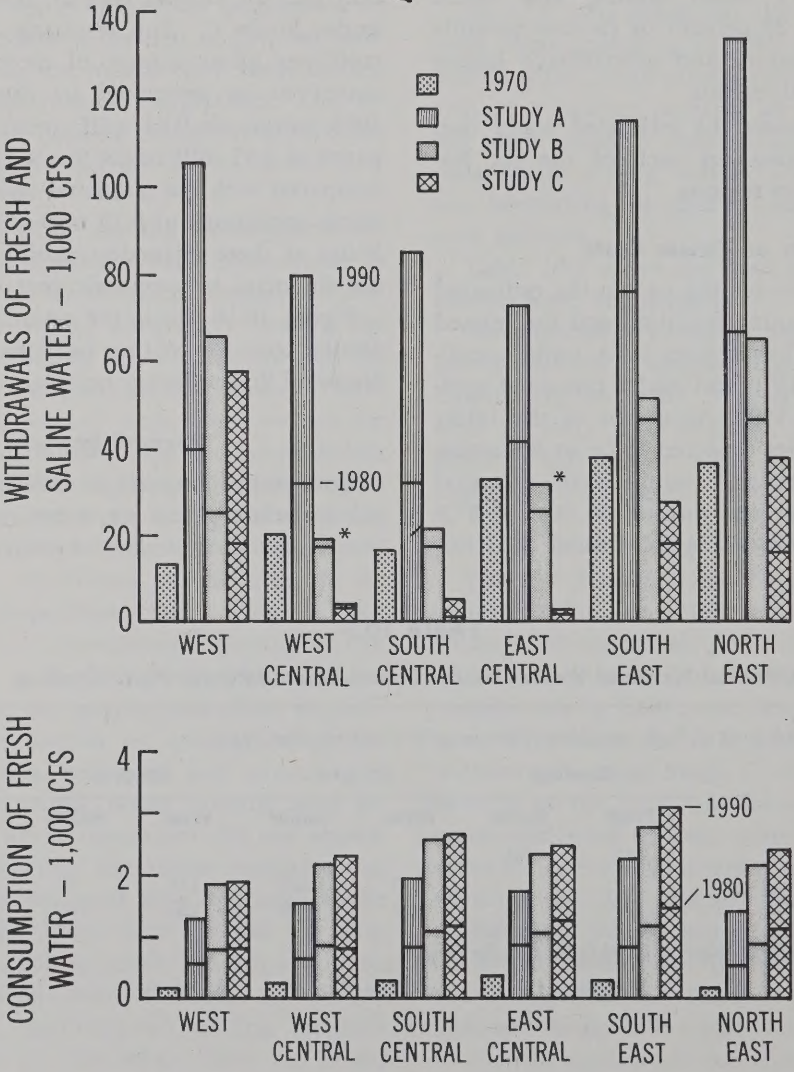
I *Average Annual Withdrawals of Fresh and Saline Water in 1,000 Cubic Feet Per Second*

Year	Existing		Study A		Study B		Study C	
	Fresh	Saline	Fresh	Saline	Fresh	Saline	Fresh	Saline
1970	111	46						
1980			153	133	114	73	8	49
1990			301	288	100	146	16	118

II *Consumptive Use of Fresh Water in 1,000 Cubic Feet Per Second*

Year	Existing	Study A	Study B	Study C
1970	1.4			
1980		4.3	5.8	6.6
1990		10.1	13.8	14.7

ESTIMATED ANNUAL WITHDRAWAL AND CONSUMPTIVE USE OF WATER FOR CONDENSER COOLING OF PROJECTED STEAM-ELECTRIC PLANTS UNDER ALTERNATIVE STUDY ASSUMPTIONS



*For these columns only withdrawals in 1980 exceed withdrawals in 1990

Figure 10.15

ESTIMATED CAPITAL AND ANNUAL COSTS FOR COOLING WATER FACILITIES FOR PROJECTED STEAM-ELECTRIC PLANTS UNDER ALTERNATIVE STUDY ASSUMPTIONS

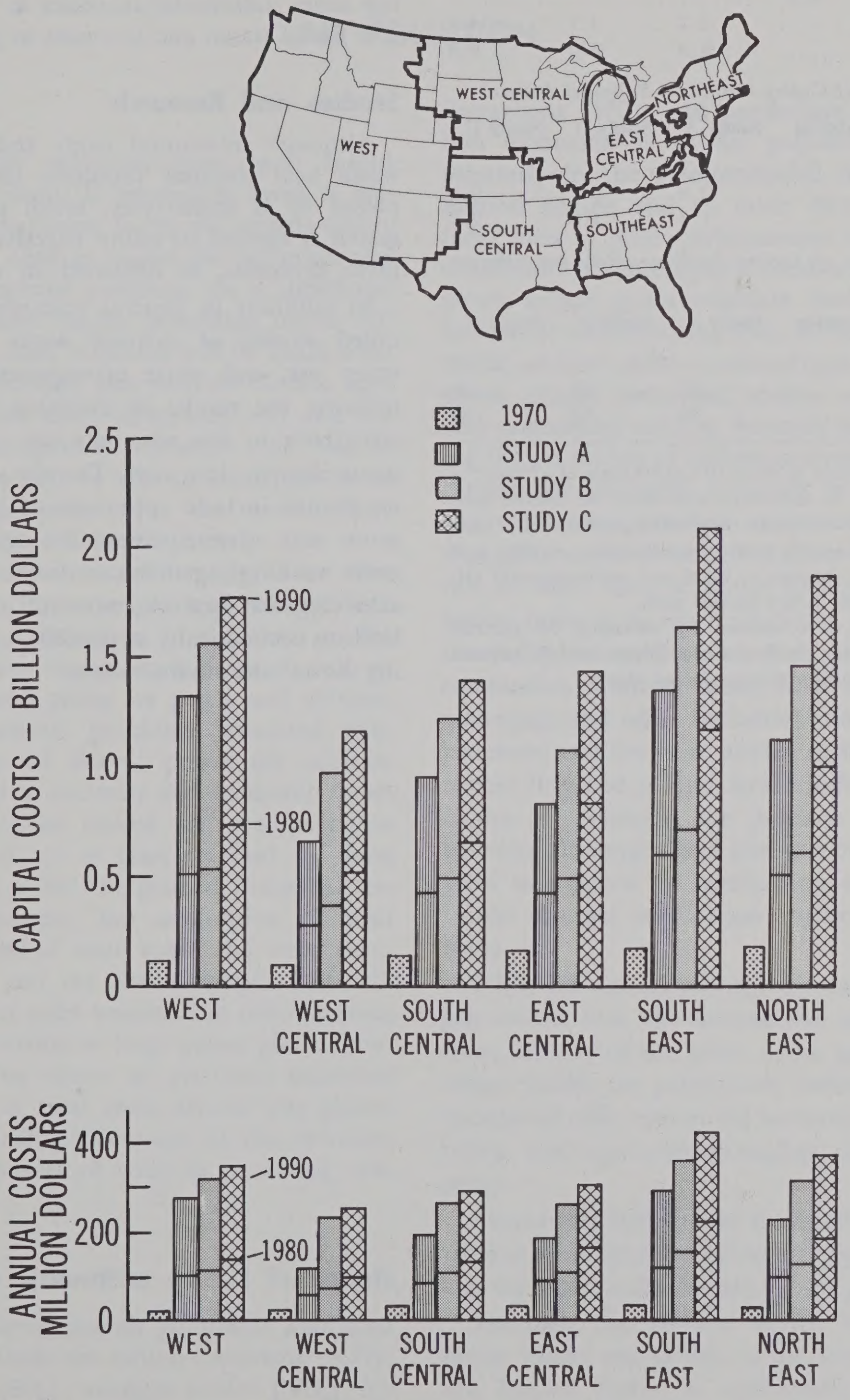


Figure 10.16

TABLE 10.4

Estimated Costs of Cooling Facilities [1]

I. *Capital Costs of Cooling Facilities in Operation in Billions of Dollars*

Year	Existing	Study A	Study B	Study C
1970	0.8			
1980		2.7	3.1	4.8
1990		6.3	8.0	9.8

II. *Annual Costs of Cooling Facilities in Billions of Dollars* [2]

Year	Existing	Study A	Study B	Study C
1970	0.1			
1980		0.5	0.7	0.9
1990		1.3	1.8	2.0

III. *Annual Costs of Cooling Facilities—Mills per Kilowatt-Hour* [2]

Year	Existing	Study A	Study B	Study C
1970	.15			
1980		.22	.28	.39
1990		.24	.33	.37

[1] All of the figures in table 10.4 show costs of a "mix" of cooling facilities. In individual situations, the annual costs in mills per kilowatt-hour may differ substantially from those shown. Escalating costs of construction, money, and fuel, and design changes to meet new environmental criteria, may increase future annual costs.

[2] These costs were derived by assuming 50 percent annual plant factor for fossil-fueled plants and 70 percent annual plant factor for nuclear-fueled plants.

ance. It appears likely, however, that the effects will fall within the range defined by Studies A and C. The tradeoffs involved will be between the use of defined mixing zones in certain water bodies, savings in the consumptive use of water, and savings in power costs vs. strict adherence to established temperature criteria without mixing zones, substantial increases in the consumptive use of water, and increases in power costs.

Studies and Research

Although substantial study and research on waste heat disposal problems has been completed or is under way, much additional research is needed to assure effective handling of these problems, as discussed in chapter 21.

In addition to general research, specific detailed studies of existing water temperature, water use, and water management conditions, utilizing the results of available research, can contribute to the wise selection of individual steam-electric plant sites. The site selection studies should include appraisals of both advantageous and adverse effects. Biologists and engineers working together can determine means of achieving the dual objectives of meeting power loads as economically as possible, and of protecting the aquatic environments.

CHAPTER 11

AIR POLLUTION

Introduction

Reducing air pollution from fossil fueled steam-electric plants to acceptable levels is one of the major challenges facing the electric utility industry. The need to resolve air pollution and other environmental problems has a significant bearing on where electric generating plants will be sited, what kind of plants will be built, what fuels will be burned, how reliable electric service will be, how much electricity will cost the consumer, and generally whether the electric utility industry will be able to keep pace in its construction program with the continuously growing demands for electric power.

The public has become acutely aware that clean air is an important natural resource, and is demanding a reduction in emissions to the atmosphere, even though such demands will result in increased prices for goods and services. The environmental problems associated with the generation of electric power are substantially exceeded in intensity and economic consequences by those caused by transportation equipment and are at least matched by those originating in either the general industrial sector of the economy, the combustion of fossil fuels in millions of small space and water heating furnaces, and the annual disposal of millions of tons of solid wastes. The concentration of energy conversion in large power plants, however, makes the effects of pollutant emissions more serious in local areas around the plants, and permits taking advantage of the technologies and economies of scale in providing controls.

Sources and Quantities of Air Pollutants

The most significant air pollutants associated with power plants are carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons (HC), and particulate matter. Carbon monoxide as an air pollutant originates primarily in the gasoline-fueled internal combustion engine and in other devices burning fossil fuels or other carbonaceous matter under conditions of incomplete combustion. Atmospheric sulfur oxides originate during the combustion of sulfur-bearing coal, oil, and, to a very much smaller extent natural gas, in electric power plants, industrial boilers, and domestic and commercial heating furnaces, and also during the processing of sulfurous materials. Hydrocarbons are produced primarily by automobiles and other transportation equipment, with only negligible amounts resulting from the combustion of fossil fuels at power plants. Particulate matter includes fly ash from power and other industrial plant stacks; soot and ash from other combustion processes; dusts from metallurgical, quarrying, and other industrial and agricultural processes; and the wear residue of such things as rubber tires and asbestos brake linings. Nitrogen oxides are primarily the products of reactions between the oxygen and nitrogen of the air supplied to support the combustion of fossil fuels in the internal combustion engine and in furnaces.

While the annual tonnage discharges of nitrogen oxides into the atmosphere are less than those for any of the other major pollutants, nitrogen oxides are particularly serious pollutants because of their role in the formation of eye-irritating and vegetation-damaging photochemical smog.

Nationwide estimates of major airborne pollutants originating from various categories of social and economic activities are shown in table 11.1.

Although the electric utility industry consumes about one-fourth of all fuel burned in the United States, it contributes only about

TABLE 11.1

Estimated Nationwide Discharges of Airborne Pollutants—1968

[Million tons]

Source	Carbon Monoxide	Particulate Matter	Sulfur Oxides [1]	Hydro-Carbons	Nitrogen Oxides [1]	Total
Transportation	63.8	1.2	0.8	16.6	8.1	90.5
Power plants	0.1	5.6	16.8	Neg.	4.0	26.5
Other fuel combustion in stationary sources	1.8	3.3	7.6	0.7	6.0	19.4
Industrial processes	9.7	7.5	7.3	4.6	0.2	29.3
Solid waste disposal	7.8	1.1	0.1	1.6	0.6	11.2
Miscellaneous	16.9	9.6	0.6	8.5	1.7	37.3
Total	100.1	28.3	33.2	32.0	20.6	214.2

Source: National Air Pollution Control Administration. (now Air Pollution Control Office, Environmental Protection Agency)

[1] Sulfur oxides expressed as tons of sulfur dioxide and nitrogen oxides as tons of nitrogen dioxide.

one-eighth of the total mass of pollutants emitted into the Nation's air. Sulfur oxides have been the most extensive air pollutant from electric utility installations. Fossil fueled power plants have, until very recently, accounted for almost one-half of the national total because of the extensive use of sulfur-containing fuels. Changes in fuel use in recent years are changing this pattern, but sulfur oxide emissions are still a major industry problem. Other significant pollutants, and the ones most difficult to control in utility furnaces, are the oxides of nitrogen. Power plants account for about one-fifth of the national total. The particulates emitted from electric power plants, which are in most cases amenable to control, also account for about one-fifth of the national total.

Estimates of 1968 power plant emissions to the atmosphere are shown in table 11.2 by type of fuel, and as a percent of the national total from all sources.

Effective emission controls are being developed and implemented, but the annual tonnage of pollutants discharged from electric power plants may continue to increase, despite continuing shifts to nuclear generation and to the use of low-sulfur coal and oil, because generation by electric utility power plants is expected to increase from 1.54 million megawatt-hours in 1970 to 5.92 million megawatt-hours in 1990.

TABLE 11.2

Estimated Emissions from Fossil-Fueled Steam-Electric Power Plants—1968

Source	MWh Generated (Million)	Sulfur Oxides		Nitrogen Oxides		Particulates	
		Amount (Million tons)	Percent of U.S. Total	Amount (Million tons)	Percent of U.S. Total	Amount (Million tons)	Percent of U.S. Total
Coal-fired	685	15.5	46.69	3.0	14.57	5.6	19.79
Oil-fired	104	1.3	3.91	0.4	1.94	0.02	0.07
Natural gas	304	([1])		0.6	2.91	([1])	
Total	1,093	16.8	50.60	4.0	19.42	5.62	19.86

Source: National Air Pollution Control Administration.

[1] Negligible.

The rate at which pollutants are emitted from a power plant burning fossil fuel depends upon the type and quality of fuel burned, design of the boiler, method of combustion, and other factors. Average emission rates from existing equipment, by type of fossil fuel, are listed in table 11.3.

In the fall of 1970, the Federal Power Commission, introduced a new questionnaire on "Steam-Electric Plant Air and Water Quality Control Data" (FPC Form 67) to collect information on the quantities of pollutants emitted and cost of pollution abatement at electric power plants. Reliable data on the electric power industry's contribution to the national air pollution problem is needed to evaluate the performance of power plants in complying with air quality control regulations.

TABLE 11.3

Emission of Pollutants at Electric Power Plants—Average Rate by Type of Fossil Fuel

	Coal	Oil	Gas
	lb/ton	lb/1000 gal.	lb/10^6 ft^3
Nitrogen dioxide	20	104	390
Sulfur dioxide	38S [1]	157S [1]	0.4
Sulfur trioxide	0.6S [1]	2.5S [1]	Negl.
Carbon monoxide	0.5	0.04	Negl.
Hydrocarbons as methane	0.2	3.2	Negl.
Aldehydes as formaldehyde	0.005	0.6	1
Particulates	17A(1–E) [2]	10(1–E) [2]	15

Btu Equivalent: 25,000,000/ton, 150,000,000/1,000 gal., 1,044,000,000/10^6 ft^3.

Source: Compilation of Air Pollutant Emission Factors, NAPCA, Durham, North Carolina, 1968.

[1] S equals percent sulfur in the fuel. For example, coal with two percent sulfur will emit 76 lbs. of SO_2 and 1.2 lbs. of SO_3 per ton of coal burned, assuming no removal of SO_x from the flue gases. In coal-fired boilers much of the SO_3 is removed with the ash.

[2] Emissions of fly ash are a function of the ash content of the fuel, type of furnace, and efficiency of the control equipment. For a dry bottom, pulverized coal unit, fly ash emissions in pounds per ton of coal burned would be 17A(1–E), where A is the ash content of the coal expressed in percent and E is the efficiency of the precipitator expressed as a decimal. For coal having an ash content of 10 percent and a precipitator operating at an efficiency of 97 percent, the rate of emissions would be $17 \times 10\,(1 - 0.97) = 5.1$ lbs./ton of coal.

Legislation and Abatement Programs

In 1967 the Clean Air Act was amended by the Air Quality Act (PL 90–148, 42 U.S.C. § 1857 et seq. 1970) to establish an intergovernmental system for the prevention and control of air pollution on a regional basis. The Department of Health, Education, and Welfare was directed to designate air quality control regions, to issue air quality criteria reflecting available scientific knowledge of the adverse effects of air pollutants on public health and welfare, and to prepare reports on control techniques for the types of air pollutants for which air quality criteria were issued. State governments were then expected to establish air quality standards for the air quality control regions and to adopt plans for implementation of the standards. The air quality standards and implementation plans were to be subject to review and approval by the Secretary of HEW.

Under the provisions of the 1967 Act, HEW's National Air Pollution Control Administration (NAPCA) delineated a number of air quality control regions. NAPCA also issued criteria and control documents for sulfur oxides, particulates, carbon monoxide, hydrocarbons, oxidants, and nitrogen oxides. The States were then responsible for adopting air quality standards and implementation plans.

A governmental reorganization plan effective on December 2, 1970, established the Environmental Protection Agency (EPA), which brings together in a single organization the major Federal pollution control programs previously existing in four separate agencies, including NAPCA, and one interagency council. The principal roles and functions of EPA include:

1. The establishment and enforcement of environmental protection standards consistent with national environmental goals.
2. The conduct of research on the adverse effects of pollution and on methods and equipment for controlling it, the gathering of information on pollution, and the use of this information in strengthening environmental protection programs and recommending policy changes.
3. Assisting others, through grants, techni-

cal assistance and other means in arresting pollution of the environment.

4. Assisting the Council on Environmental Quality in developing and recommending to the President new policies for the protection of the environment.

The Clean Air Act Amendments of 1970 (PL 91–604, approved December 31, 1970, 84 Stat. 1676) greatly strengthened Federal air pollution control authority. Within 30 days following the enactment, the Administrator of the Environmental Protection Agency (EPA) was directed to issue national primary and secondary ambient air quality standards. As defined in the Act, primary ambient air quality standards are those required to protect the public health. Secondary ambient air quality standards are those required to protect the public welfare from any known or anticipated adverse effects. Table 11.4 lists EPA's standards for certain pollutants.

Within nine months after promulgation of ambient air quality standards, the States are required to submit implementation plans to the Administrator. An extension of up to 18 months may be granted for submitting implementation plans for secondary standards. The Administrator is to approve or disapprove a plan within four months after the date required for its submission. Approved State plans for implementing primary standards must be carried out within three years, except that an extension of up to two years may be granted. Plans for implementing secondary standards must be carried out within a reasonable time.

The 1970 Act requires the Administrator to issue a list of pollutants which in his judgment have an adverse effect on the public health and welfare. Within 12 months after a pollutant has been listed, the Administrator is to issue air quality criteria concerning that pollutant and information on control technology, including costs.

The Act treats new stationary sources in a special way. Within 90 days after adoption of the Act, the Administrator is to publish a list of categories of stationary sources and within 120 days following he is to propose regulations establishing Federal standards of performance for new sources within each category. The Act defines standard of performance as a standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best available technology, giving consideration to economics, which the Administrator determines has been adequately demonstrated. Each State then develops and submits to the Administrator procedures for implementing and enforcing the standards. If the Administrator finds the State procedures adequate, he delegates to that State his authority under the Act to implement and enforce the standards.

The 1970 Act also specifies that all Federal facilities shall comply with Federal, State, interstate, and local requirements respecting control and abatement of air pollution to the same extent as persons subject to such requirements, unless exempted by the President.

Earlier, Executive Order 11507, issued in February 1970, required Federal facilities to conform to the air and water pollution standards of the State or locality in which they are situated. It was the intent of this Order that the Federal Government in the design, operation, and maintenance of its facilities would provide leadership in the nationwide effort to protect and enhance the quality of air and water resources. The Order superseded an earlier Order of May 1966, although some of the provisions of the earlier Order limiting emissions of sulfur oxides from Federal facilities located in the New York, Chicago, and Philadelphia air quality control regions remain in force. These limits are shown in table 11.5. The 1966 Order framed emission limitations in terms of pounds per million Btu of heat input and, therefore, they permit sulfur oxide emissions to be controlled in any feasible manner, without necessarily limiting the sulfur content of the fuels.

TABLE 11.4

Ambient Air Quality Standards

	Limiting Concentrations in Micrograms per Cubic Meter		
	SO_x	NO_x	Particulates
Primary Standards			
24-hour	365	250	260
Average annual	80	100	75
Secondary Standards			
24-hour	260	250	150
Average annual	60	100	60

TABLE 11.5

Recommended Maximum Emission Rates of Sulfur Oxides

[Federal Facilities]

New York Interstate Air Quality Control Region	0.35 pounds per million Btu (gross value)
Chicago Interstate Air Quality Control Region	0.65 pounds per million Btu (gross value)
Philadelphia Interstate Air Quality Control Region	0.65 pounds per million Btu (gross value)

Source: 42 Code of Federal Regulations Part 476.

State and local agencies have been promulgating air pollution regulations that directly affect power plants. Limits have been set on both emissions and the sulfur content of fuels. In the Los Angeles, California, Air Pollution Control District, for example, a regulation promulgated in 1969 restricts building of new, or expansion of existing, fuel burning equipment whose operation would cause discharges into the atmosphere of more than 200 pounds per hour of sulfur oxides, 140 pounds per hour of nitrogen oxides, or 10 pounds per hour of particulates. Los Angeles County has a regulation which limits the sulfur in solid or liquid fuels burned in the County to 0.5 percent and New York City is considering 0.3 percent. With the current level of technology, these limits make the use of coal or oil-fueled electric generating units tremendously expensive, if not impossible.

Emergency plans to combat air pollution episodes are being developed in some areas. Chicago, for example, has designed a plan which would require power plants to shift to low-sulfur, low-ash fuels (of which each plant must have a firm 4-day supply), to shift loads to different power plants within the city, or possibly to import power from outside the city, in case of critical pollutant concentrations. New Jersey has proposed emergency air pollution regulations that involve using cleaner fuels, soot blowing and boiler lancing during periods of the day when atmospheric turbulence can assist in dispersion, and diverting power generation to facilities outside the affected area when emergencies develop.

In California, the Monterey-Santa Cruz Unified Air Pollution Control District passed nitrogen oxide emission regulations that went into effect September 1, 1969. Flue gas concentrations of oxides of nitrogen emitted into the air may not exceed 500 parts per million. The limit could be reduced to 350 parts per million if conspicuous plumes are not eliminated. This is one of the first regulations for NO_x from a stationary combustion source.

Air Pollution and Reliability of Electric Power Supply

Fears of the potentially harmful effects of power plant emissions and uncertainties of ultimate air quality objectives and methods of achieving these objectives (including the setting of pollutant emission standards), coupled with other environmental control issues such as thermal pollution, esthetics, and land use, pose difficult technological and managerial problems and sometimes lead to protracted delays in decisions on the siting or in the construction of electric power plants.[1]

A clean, salubrious environment and an adequate, economical and reliable power supply are both desirable. However, the technology to accomplish both goals simultaneously has not been completely developed. Until it is, a series of balanced compromises may be necessary. As time progresses, greater research and development should bring forth solutions which, at a bearable cost, will make possible reliable electric service without appreciable effect on the Nation's environment.

Emissions from Fossil-Fueled Power Plants

Air pollutants from fossil-fueled power plants are the direct result of fuel combustion. Each fuel contributes pollutants in accordance with its chemical composition and the conditions under which it is burned. While the percentage of electric energy generated from fossil fuels is expected to diminish from about 82 percent in 1970 to about 44 percent in 1990, the kilowatt-hours produced by fossil fuel power plants will increase steadily, as indicated by table 11.6. Thus, development of an effective emission control technology is essential if the electric power industry's expected contribution to improvement of national air quality is to be realized.

[1] Discussed in more detail in chapter 16.

TABLE 11.6

Estimated Electric Utility Production of Electric Power by Primary Energy Source

Fuel or Energy Source	1970		1980		1990	
	Million MWh [1]	(%)	Million MWh [1]	(%)	Million MWh [1]	(%)
Fossil fuel	1,262	81.8	1,922	61.8	2,628	44.3
Nuclear	22	1.4	874	28.1	2,913	49.2
Hydro	257	16.8	317	10.1	381	6.5
Total	1,541	100.0	3,113	100.0	5,922	100.0

[1] Includes energy for pumped-storage pumping: 6, 38, and 94 million MWh, respectively, for 1970, 1980, and 1990.

Emissions from Combustion of Coal

Annual consumption of coal by electric utilities is expected to more than double in absolute quantity during the next two decades. The principal constituents in coal that contribute to air pollution are sulfur and ash. The sulfur occurs primarily in organic and pyritic forms and is transformed by the combustion reaction into sulfur dioxide (SO_2) and sulfur troxide (SO_3). The ash is a complex of non-combustible materials, which end up as slag, dry bottom ash, and fly ash.

From 10 to 50 percent of the pyritic sulfur in coal, depending upon the type of coal, may be removed at the mine by a washing process. Utility coals are sometimes washed at the coal preparation plant, primarily to reduce their ash content. An additional five to ten percent of the pyritic sulfur can be removed by more intensive preparatory methods and the installation of special equipment to handle finely ground coal at the power plant.

The use of low-sulfur coal—coal containing less than one percent sulfur by weight—is the simplest method of reducing sulfur dioxide emissions at coal-burning power plants, but the supplies of low-sulfur coal are often either committed to steel production and export, or situated in deposits far removed from existing power plants. Such coals are generally high in price and are difficult to obtain in sufficient quantities to meet the needs of electric utilities. They frequently cannot be used in slag tap furnaces because of the higher viscosity of their ash and its higher fluid temperature. Moreover, the use of this fuel tends to increase emissions of particulate matter because most electrostatic precipitators are less efficient when there is less sulfur dioxide in the flue gases. Finally, the heat content of low-sulfur coal may be lower than for other available types, so more of it must be burned per kilowatt hour.

Consideration is being given to processes which would remove both sulfur and ash from coal prior to combustion, such as solvent refining of coal and conversion of coal to a low-Btu gas at the plant site. The latter process differs from current investigations of converting coal to high-Btu pipeline quality gas, as discussed in chapters 4 and 21.

Emission from Combustion of Fuel Oil

Sulfur is also the principal air pollutant resulting from combustion of fuel oil in power plants. The non-combustibles in fuel oil are usually so low that the fly ash problem is limited to emissions of acid smut. Because of the high cost of transporting fuel oil over land, use of fuel oil in power plants has been essentially restricted to sites accessible to tanker or barge transportation, or at sites adjacent to petroleum refineries.

Sulfur oxide emissions from combustion of fuel oil are expected to diminish in the future because the petroleum industry is responding to environmental needs by expanding its capacity to supply low-sulfur fuel oil, and is expected, on a world-wide basis, to supply large quantities of such fuel to meet most air quality regulations.

Air Pollution from Combustion of Natural Gas

Compared with coal and fuel oil, combustion of natural gas is not a significant source of air

pollution. Some raw natural gas contains sulfur in the form of hydrogen sulfide, but most of this is removed before marketing to protect pipelines and compressors from excessive corrosion. Thus, natural gas delivered to power plants is essentially sulfur free and not a significant source of sulfur dioxide pollution. Natural gas may contain small amounts of nitrogen which may enter into reactions in the boiler furnace to influence production of nitrogen oxides, but these oxides are essentially the products of the combustion and originate in the consitituents of the combustion air rather than the constituents of the fossil fuel, as discussed in the section on Nitrogen Oxides.

Coal can be converted to synthetic gas which can be burned without emission of sulfur oxides. The delivered cost of synthetic gas, however, is relatively high in most areas of the country. Use of it as a source of primary energy for electric power generation prior to 1980 does not appear to be promising, but because of the long-range potential of synthetic gas, the subject is discussed more extensively in chapters 4 and 21.

The problems of fossil fuel desulfurization and coal gasification are also discussed in the Federal Power Commission's staff report on "Air Pollution and the Regulated Electric Power and Natural Gas Industry." The Bureau of Mines and the Office of Coal Research are pursuing additional research into the area of coal conversion.

Sulfur Oxides

In most utility combustion processes approximately 90 to 95 percent of the sulfur in fossil fuels is oxidized and enters the flue gas as sulfur dioxide (SO_2) and sulfur trioxide (SO_3), with about 97 percent of the SO_X being in the form of sulfur dioxide gas. The overall sulfur oxide content of flue gas is in the range of 0.2 to 0.4 percent of the total gas volume for plants using two to three percent sulfur coal, making removal or recovery of sulfur dioxide gas from power plant exhaust systems difficult. Sulfur dioxide can be injurious to human and animal health and to vegetation. It can also have a deleterious effect on painted surfaces, metals, building materials and fibers.

The small quantities of sulfur trioxide (SO_3) are emitted more in the form of an aerosol than as a gas. Sulfur trioxide is highly corrosive, one reason being that it readily combines with water to form sulfuric acid. Corrosion from SO_3 affects power plant air heater tubes and plates, and duct work, as well as the environment outside the power plant. Sulfur trioxide is a highly objectionable constituent in a plume.

Nitrogen Oxides

Nitrogen oxides from power plants are primarily a function of the high furnace temperature and nitrogen content of the air in the combustion zone. Within the 2800° to 4000°F. temperature range, oxygen and nitrogen in the combustion air combine to form nitric oxide (NO). A small amount of NO oxidizes within the boiler to form nitrogen dioxide (NO_2), but the major portion is emitted to the atmosphere where further oxidation to NO_2 occurs. Once in the atmosphere, the nitrogen oxides under the influence of sunlight enter into complex chemical reactions to form photochemical smog and ozone, both highly irritating to the eyes and damaging to vegetation. In fogs, nitrogen dioxide may combine with water to form nitric acid which can cause corrosive damage to plants and materials and irritate the lungs.

The formation of nitrogen oxides in the combustion zone depends not only on flame temperature, but also on the excess air supplied to support combustion, the kind of fuel burned, the position of the burner flame relative to furnace walls, and the configuration of the furnace cavity. While a reduction of excess air tends to reduce nitrogen oxide formation, this stratagem introduces the probability of some incomplete combustion and increased formation of carbon monoxide which ordinarily is present in negligible amounts.

Since nitrogen oxide formation is primarily a function of the furnace temperature, pulverized coal combustion is the greatest producer of nitrogen oxides among the fossil fuels. Residual oil is next and natural gas last. In general, nitrogen oxides are more difficult to control than sulfur oxides. Little has been done to devise means for nitrogen oxide reduction in comparison to the work done on sulfur oxide reduction. A research and development plan to establish control technology has recently been completed by Esso Research and Engineering Company under contract to EPA.

Particulates

Coal and, to a lesser extent, residual fuel oil contain incombustible materials that are converted to slag, dry bottom ash, or fly ash. Particulate matter emitted from coal combustion is a mixture consisting primarily of carbon, silica, alumina, calcium, and iron oxide. Particulate matter emitted from fuel oil combustion consists of ash, including sulfates, and, under poor combustion conditions, partially burned droplets of oil. The two main variables affecting fly ash formation and emission are ash content of the fuel and the manner of firing.

Coal used in power plants normally contains from 5 to 20 percent ash, averaging about 10 to 11 percent for the Nation. Most fuel oils contain less than two-tenths of a percent of incombustible matter, while natural gas is essentially ash free. Particulate matter emissions from natural gas combustion are caused primarily by dust particles in the gas. Smoke or soot due to incomplete combustion of any fuel may also be emitted, but these should be minuscule in properly run, high-efficiency power plants. Combustion air carries some of the ash out of the furnaces in the form of fly ash.

Fly ash emissions from furnaces are affected in part by how the coal is fed into the furnace, the size of the coal burned, and whether the coal is burned in suspension or on a grate. In a dry bottom furnace, pulverized coal firing at temperatures near the melting point of the ash produces a large amount of fine fly ash (about 80 percent of the original ash in the coal). In cyclone furnaces, and in other wet bottom furnaces, crushed or pulverized coal is burned at high temperatures which causes the ash to melt and flow to the bottom of the furnace where it may be tapped into a pool of water. This results in low amounts of fly ash (as low as 20 percent of the original ash in the coal). Intermediate amounts of fly ash are produced in stoker-fired furnaces. However, relatively few stoker-fired furnaces are used in power plants. Most fly ash can be collected in mechanical and electrostatic precipitators which today can achieve efficiencies on the order of 99 percent. Currently available fly ash collectors are relatively inefficient in removing the fine particulates (less than 1–2 microns in diameter), and total emissions of fine particulates will continue to increase until improved control technology is made available through research and development.

Other Pollutants from Fossil-Fueled Plants

Other pollutants, such as aldehydes, polynuclear hydrocarbons, carbon monoxide, and gaseous hydrocarbons are a very small proportion of the total emissions from power plants due to the highly efficient combustion achieved. Hydrochloric acid and trace metal emissions may arise when they are present in the coal. If attempts are made to reduce nitrogen oxides by reducing the amount of excess air, an increase in the amounts of carbon monoxide, particulates, and hydrocarbon compounds may result. Use of less excess air would also tend to increase the carbon content of the fly ash.

Other problems that may arise under certain conditions involve the fog or spray produced by moisture from large evaporative cooling systems. The fog may reduce visibility in local areas and may cause icing problems in cold weather. The interaction of merging cooling tower plumes and stack plumes as shown in figure 11.1, may encourage development of photochemical smog. These problems have not been severe in the past, but they may be more common to the large capacity plants being planned for the future.

Gaseous Emissions from Nuclear Power Plants

Nuclear power plants do not emit significant quantities of air pollutants. While nuclear reac-

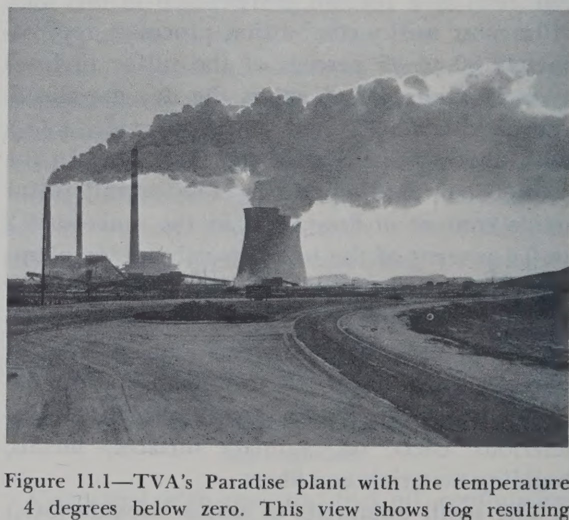


Figure 11.1—TVA's Paradise plant with the temperature 4 degrees below zero. This view shows fog resulting from the stack and cooling tower plumes.

tors produce large quantities of radioactive materials, virtually all of these are contained in the fuel assemblies or collected in solid waste products and are not factors in air pollution. These solid waste materials are subject to several levels of control, collection, and treatment.

Small quantities of low-level radioactive gases are collected from the nuclear heat generating process and are either released to the atmosphere under carefully controlled conditions or are concentrated and stored.

The release limits are based on radioisotope concentration guides established by international and national radiological authorities.

The Atomic Energy Commission is responsible for enforcement of the established release rates. Current evaluations of present and future radioactive emissions from nuclear power plants indicate that these controlled releases do not now, and are not likely in the future to produce any measurable effect on man or the environment.

A more complete description of nuclear power generation and related products of nuclear fission, the concentration guides and standards for radioisotopes, waste management and treatment, and public health programs is contained in chapter 6, Nuclear Power.

Status of Emission Control Technology for Fossil-Fueled Plants

A fully tested and acceptable control technology relating to the three significant air pollutants originating in power plant operations exists only for particulate matter, although removal of the submicron size fraction is a most difficult task. Control technology for gaseous pollutants is still in various stages of development. More than 40 different control processes have been suggested and many are being tested, either in the laboratory or in pilot demonstrations. One process is at the full scale demonstration stage, and one has been declared fully developed and ready for commercial application with a removal efficiency believed to be in the order of 60 percent. There is not yet available, however, a fully tested and commercially acceptable process for the control of gaseous pollutants compatible with actual power plant operation.

Control of Sulfur Oxides

The principal thrust of current research and development in air pollution control processes for power plants is in the field of sulfur oxides control. EPA has sponsored and coordinated research programs related to fuel desulfurization and flue gas cleaning processes. Other government agencies such as TVA and the Bureau of Mines, private industry in general, and the electric power industry in particular, are participating in research and development of flue gas desulfurization techniques, some of which are described below.

Absorption by Limestone or Dolomite

Of the several processes that have been proposed to remove sulfur oxides from stack gases, injection of limestone or dolomite into the boiler furnace, or the use of such materials, calcined or uncalcined, in a wet scrubber operation may offer the least expensive method of control. Hypothetically, the limestone process can be adapted to any size installation. It can also be added to existing power plants if space for retrofitting is available. This method does not yield a product of commercial value.

The dry limestone process involves injecting pulverized limestone into the combustion chamber to react with SO_2. This method may remove about 30 percent of the SO_2 depending on the quality and quantity of limestone added and numerous operating variables. A limiting factor at existing plants is the capacity of existing dust collection equipment to remove the added limestone from the stack gases. If SO_2 removal efficiencies of 50 to 60 percent are to be attained, it may more than double the dust loading of dust collectors. The method is considered a dry process in that no scrubbing device is used to collect fly ash.

The wet scrubbing limestone process has possibilities of removing over 80 percent of the sulfur oxides. It employs an aqueous lime or limestone slurry, made either by injecting limestone into the boiler and catching the resulting lime in the scrubber, or by introducing finely ground limestone directly into the scrubber. The wet process can remove particulate matter as well as sulfur oxides (figure 11.2).

A wet limestone process was installed in 1968 on the No. 2 unit (140 megawatts) at the Mer-

amec plant of the Union Electric Company near St. Louis, Missouri, and in 1969 on a 125-magawatt unit at the Lawrence station, Lawrence, Kansas, of the Kansas Power and Light Company. These wet systems were expected to remove at least 82 percent of the SO_2 and 99 percent of limestone dust and fly ash. As a prototype developmental installation, the system experienced a host of operational problems; however the Kansas Power and Light Company is installing the same control system on a new 430-megawatt unit, the largest in the State of Kansas, also at the Lawrence station.

The wet scrubbing process has several advantages over the dry process, including higher efficiency for SO_x removal, possibly less boiler operation interference, and generally lower operating costs for large power plants. Also, less limestone is required for effective SO_2 removal, thereby providing some economics for limestone purchases, material handling facilities, and solid waste disposal. The wet process has the disadvantage of requiring reheat of the exhaust gases after scrubbing in order to achieve proper plume rise. The water pollution potential of the scrubbing solution is an additional disadvantage. On balance, the wet process appears to be better suited to large generating units, even though the dry process releases gas at higher temperatures, requires less capital investment, and is simpler to operate.

Catalytic Oxidation

In the catalytic oxidation process, depicted in figure 11.3, hot flue gases are first passed through a high-temperature, high-efficiency electrostatic precipitator to remove fly ash. The clean gas then passes through a catalytic bed of vanadium pentoxide where the SO_2 is oxidized to SO_3. The flue gases are cooled sufficiently to condense and to collect a sulfuric acid mist. The by-product is a moderately concentrated sulfuric acid. One problem of this process is that a high flue gas temperature is necessary for the oxidation reaction. This requires expensive gas cleaning and handling equipment capable of operating at 800°F to 900°F. Furthermore, fly ash tends to foul the costly catalyst if the gas stream is insufficiently cleaned. High temperature precipitation is expensive. Costly corrosion-resistant materials are needed through much of the exhaust system, especially in the absorber and demister portions.

SULFUR REMOVAL BY WET LIMESTONE PROCESS

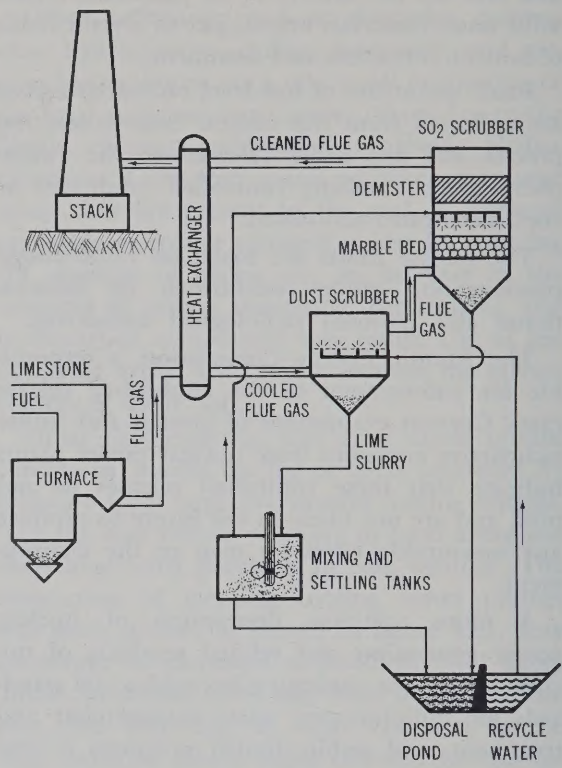


Figure 11.2

A pilot installation has been successfully operated at the Portland station of Metropolitan Edison Company. On the basis of experience acquired in the small scale installation, designed to treat 6% of the stack gas from a 250 megawatt unit, the first full scale commercial Cat-Ox installation is now being constructed to operate with the 100-megawatt Number 4 unit of the Wood River station of Illinois Power Company. This demonstration installation, scheduled for completion in mid-1972, is financed jointly by the Air Pollution Control Office of the Environmental Protection Agency and the Illinois Power Company.

The Kiyoura-Tokyo Institute of Technology Process (figure 11.4) is similar to the catalytic oxidation process. After the gases pass through the catalytic reactor, ammonia gas is injected. The result is formation of 99 percent pure am-

CATALYTIC OXIDATION PROCESS FOR THE REMOVAL OF SO_2 FROM FLUE GASES

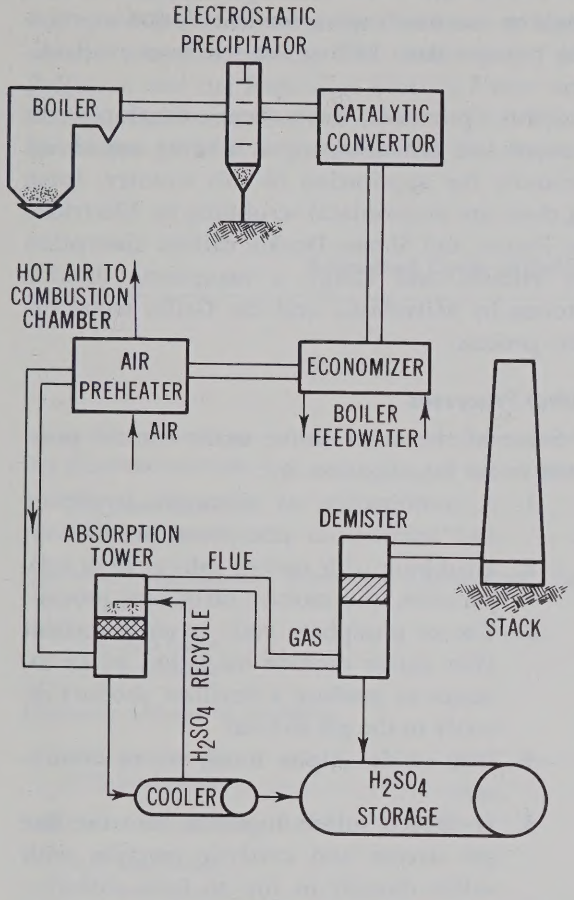


Figure 11.3

KIYOURA - TOKYO INSTITUTE OF TECHNOLOGY PROCESS FOR REMOVAL OF SO_2 FROM FLUE GASES

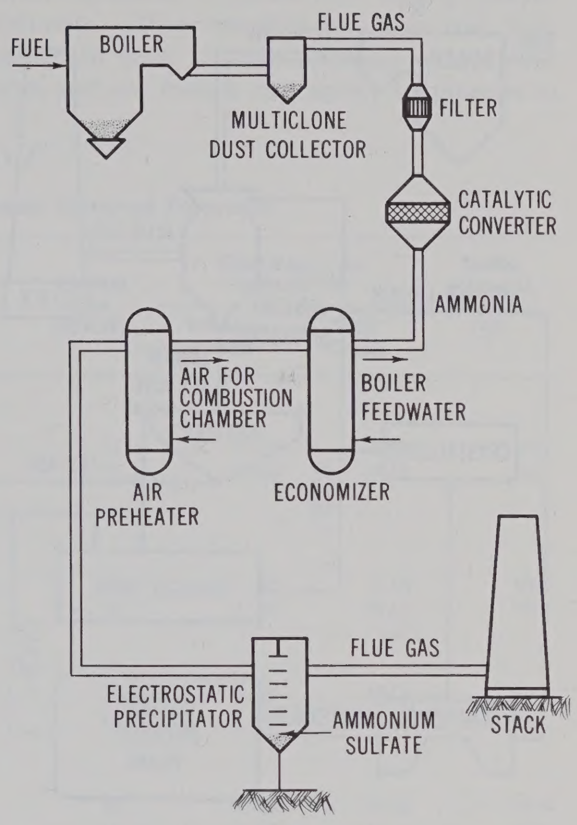


Figure 11.4

monium sulfate crystals that can be used for fertilizer. There is, however, a very limited market for ammonium sulfate in this country. Kiyoura has reported that the ammonium sulfate process can be adapted to manufacture ammonium phosphate fertilizer which would have higher unit value.

A sulfur dioxide removal process in which gas cleaned in a precipitator is scrubbed in a solution of potassium sulfite is under development. The scrubbed solution can be thermally stripped to evolve SO_2 gas from which either elemental sulfur or sulfuric acid can be produced. The process has high sulfur removal efficiency, as has been demonstrated at Tampa Electric Company's Gannon Station, but was tested with little success on a full scale at Baltimore Gas & Electric Company's Crane Station.

Alkaline Scrubbing

An alkaline scrubbing process for fly ash and SO_2 removal from flue gasses is being developed. Magnesium oxide slurry would be used directly in a venturi-type scrubber. The resulting magnesium sulfite will be separated, dried, and heated to evolve a concentrated stream of SO_2 and to regenerate magnesium oxide for recycling. The SO_2 will be converted to sulfuric acid or reduced to elemental sulfur. A sketch of this process is shown on figure 11.5. Because of the high cost of absorbent regeneration, the idea of a central recovery plant which would receive sulfite salts from several power plants and other industrial sources and return the regenerated absorbents to these sources has been proposed.

ALKALINE SCRUBBING PROCESS FOR REMOVAL OF SO_2 AND FLY ASH FROM FLUE GASES

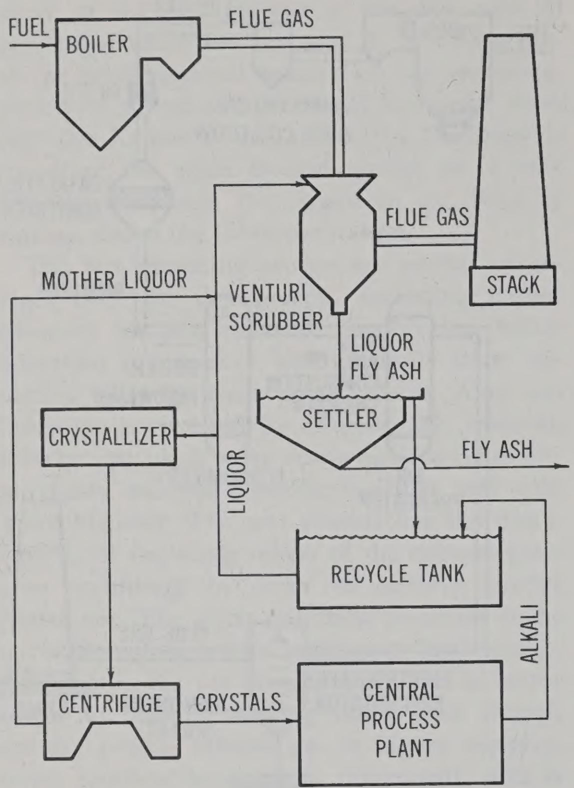


Figure 11.5

Solid Absorbents

Two processes for sulfur removal from stacks, based on solid absorbent methods, are the Reinluft process and the Alkalized Alumina process. In each case, a solid absorbent is used to collect SO_2. The Reinluft process regenerates activated char to release SO_2 which is then utilized in the manufacture of high-grade sulfuric acid. The tendency of the char to ignite, in addition to the complexity of operation, makes the Reinluft process unpromising for the present and it has been withdrawn from the market. An advantage of the Alkalized Alumina process is that elemental sulfur could be manufactured from the hydrogen sulfide extracted during regeneration of the absorbent. Elemental sulfur is easier to store or ship than acid. There are, however, several drawbacks to the process. Alkalized alumina absorbent pellets tend to disintegrate upon repeated regeneration and the process, like other regenerative processes, is nearly as complex as the operation of the power plant. It also requires too much space for installation at existing power plants having limited land availability.

Other processes have been developed in Europe and Japan, but none is being considered seriously for application in this country. Some of these are ammoniacal scrubbing by Electricite de France and Showa Denko, carbon absorption by Hitachi and Lurgi, a manganese dioxide process by Mitsubishi, and the Grillo metal oxides process.

Other Processes

Some of the other sulfur oxide control processes under investigation are:

1. A combination of ammonia scrubbing and ammonium phosphate production;
2. Scrubbing with molten salts at high temperature, the molten carbonate process;
3. Use of phosphate rock as an absorbent after sulfur dioxide oxidation in an attempt to produce a fertilizer product directly in the gas stream;
4. Iron oxide (alpha form) as an absorbent;
5. Hydrogen sulfide injection into the flue gas stream and catalytic reaction with sulfur dioxide *in situ* to form sulfur;
6. Carbon monoxide injection into the flue gas stream, followed by catalytic reaction with sulfur dioxide to form sulfur;
7. Absorption by sodium hydroxide solution followed by regeneration by electrolysis;
8. Absorption by potassium polyphosphate;
9. Oxidation by nitrogen oxides;
10. Use of zinc oxide as absorbent;
11. Absorption by manganese dioxide followed by dry regeneration;
12. Absorption by barium carbonate slurry and reduction to sulfur;
13. Use of metal oxide as absorbent followed by reduction in place;
14. SO_2 absorption process using cooled absorbent in a high mass transfer efficiency controlled vortex gas scrubber;
15. Use of gaseous ammonia with regeneration of the ammonia gas for reuse. The process would also remove some NO_x;

16. Use of potassium formate which is regenerated after recovery of elemental sulfur.

For more detailed information on some of these control processes, see the FPC staff report "Air Pollution and the Regulated Electric Power and Natural Gas Industries," or *Control Techniques for Sulfur Oxides* as published by the Department of Health, Education, and Welfare, NAPCA, Publication AP-52.

The process costs of the various methods for removing SO_x from flue gases will not be known until experience is gained from large prototype full-scale utility installations. The cost data shown in table 11.7 are the most recent available and are from a cost survey in progress at

TABLE 11.7

Estimated Costs of Sulfur Dioxide Removal Processes

Process	Capital Cost ($/KW)	Operating Cost (mills/KWh) Without Credit	Operating Cost (mills/KWh) With Credit	Sulfur Removal Efficiency (%)
Dry limestone injection				
55% load factor	11.6	0.82	N/A	50
75% load factor	11.6	0.68	N/A	50
Limestone injection-wet scrubbing (Combustion Engineering, APCO-TVA) [1]				
55% load factor	20.5	1.42	N/A	90+
75% load factor	18.6	1.08	N/A	90+
Limestone add-on-wet scrubbing				
55% load factor	20.0	1.41	N/A	85
75% load factor	18.5	1.10	N/A	85
MgO Scrubbing (Chemico)				
55% load factor	20.1	1.25	0.82	90+
75% load factor	18.7	0.87	0.44	90+
Lime add-on-scrubbing (Bahco)				
55% load factor	13.8	1.32	N/A	95
Stone and Webster/Ionics				
55% load factor	21.0	1.39	1.06	95
75% load factor	19.5	0.96	0.52	95
Wellman/Lord				
55% load factor	[2] 12.6	0.96	0.55	90
	[3] 13.5	1.05	0.79	85
75% load factor	[2] 12.6	0.80	0.39	90
	[3] 13.5	0.88	0.62	85
Cat-Ox (Monsanto)				
55% load factor	36	2.56	2.17	85
75% load factor	32	1.44	1.03	90

Source: Adapted from Survey of Processes and Costs for SO_x Control on Steam-Electric Power Plants, Division of Process Control Engineering, Air Pollution Control Office, Environmental Protection Agency, February 1971.

[1] The Combustion-Engineering Process was designed for two specific locations and is not readily translatable to other situations. The APCO-TVA project embodies a different design philosophy and is intended to provide a broader-based capability.

[2] With acid recovery plant.

[3] With sulfur recovery plant.

1. Plant size: 1,000 megawatts
2. Load factor (two cases): 55% for existing plants
   75% for new plants
3. Percentage sulfur in coal: 3.5%
4. Fixed charges:
   7% depreciation
   3% taxes & insurance
   8% cost of money

   Total 18% (annual percentage of capital investment)
5. Variable charges:
   labor @ \$5.00/hr. + 150% overhead
   maintenance @ 5% annually of capital
   electricity @ 6 mills/kilowatt-hour
   fuel gas or oil @ 45¢/10^6 Btu
   coal @ 35¢/10^6 Btu
   limestone @ *2.05/ton
   cooling water @ 10¢/1,000 gallons
6. Credits for by-products:
   acid (100%) @ *10/ton
   sulfur @ *20/ton
7. Heating value of coal: 11,800 Btu/lb
8. Power station efficiency: 34.1%, equivalent to 10^4 Btu/kilowatt-hour

the Air Pollution Control Office of the Environmental Protection Agency.[2] The costs shown are probably the lowest that can be obtained. The assumed plant size for the table is 1,000 megawatts. A 55 percent load factor is assumed for an existing plant to which the equipment would have to be retrofitted and a 75 percent load factor is assumed for a new plant which would incorporate the process in the original design.

Control of Nitrogen Oxides

There are several possible means of controlling power plant emissions of nitrogen oxides. Control may be accomplished either by minimizing formation of the oxides or by removing them from the flue gas.

It is difficult to achieve complete control of NO_x in power plants because of the interacting effects of other pollutants. The conditions favorable to high NO_x production are a result of combustion practices to achieve better power plant operating efficiency and to control other air pollutants. Present combustion practices are designed to produce a clean, smoke-free, hot flame that is close to the maximum temperature attainable to get the most out of the fuel in terms of heat recovery and economy. Power plant boilers are designed to use high flame temperature and excess air to control air pollutants such as smoke, carbon monoxide, and unburned fuel. These parameters will produce high levels of nitric oxide (NO) which represents 90 to 95 percent of the NO_x found in the flue gas. NO_2 comprises essentially all of the remaining five to ten percent of the NO_x.

[2] Survey of Processes and Costs for SO_x Control on Steam-Electric Power Plants, Air Pollution Control Office, February 9, 1971.

Controls for NO_x produced by coal-fired systems have not been studied extensively on a commercial scale nor have the problems associated with NO_x production from coal firing been solved. Tall stacks for better dispersion of flue gases may help to reduce ground level concentrations of NO_x as well as other pollutants under favorable meteorological conditions.

Large fossil-fueled power plants can use combustion modifications such as low excess air, two-stage combustion, flue gas recirculation, or steam or water injection, or combinations of these methods to reduce NO_x emissions, but all of these methods reduce burner efficiency. Additionally, all fossil fuel-fired power plants utilizing SO_2 wet scrubbing processes may reduce the nitrogen oxide emissions. Pilot studies have indicated that the wet limestone process, other liquid alkali techniques, and gaseous ammonia additions remove some of the NO_x present. This is apparently due to the NO_2 and NO acting together in equal amounts to combine with the additive material. Alkaline scrubbing appears to have the most promise, but to date no process has been developed for the specific purpose of removing NO_x from flue gases.

Control techniques based on burner design or firing methods work to produce a lower overall furnace temperature. Tangentially fired or corner fired furnaces produce a relatively long luminous flame. Overall furnace temperatures are lower. This firing method generally produces lower NO_x emissions than horizontally fired boilers.

The two-stage combustion technique operates on the principle that less NO_x is produced in the high temperature flame region (first stage) because of an oxygen shortage. In two-stage

combustion, 90 to 95 percent of the theoretical (stoichiometric) amount of combustion air is injected at the burner; 15 to 20 percent of the stoichiometric amount of combustion air is injected a few feet downstream from the burner (second stage). This method may reduce formation of nitrogen oxides 40 to 50 percent.

Lowering overall excess air may sometimes cause a reduction in NO_x concentrations. Because of lower oxygen concentrations, less nitrogen oxides are formed, but a decrease in excess air also increases peak combustion temperatures which cause a higher rate of NO_x formation. The method of firing and the furnace design appear to affect the rate of NO_x formation as a function of excess air.

Flue gas recirculation or injection of steam reduces emissions of NO_x by cooling furnace and flue gas temperatures. Use of silica gels as a means of converting NO to NO_2 with absorption of NO_2 by the silica gel has a low collection efficiency and high expense for power plant operation. Problems with either fly ash fouling of catalysts, or gels, or low reactivity at the prevailing low flue gas temperatures have not been solved.

At the present time, modifications in combustion techniques and furnace design appear to be the most effective means for reduction of nitrogen oxides emanating from power plant operations.

Control of Particulates

Advances in automatic combustion controls have helped eliminate smoke nuisance from power plants, and the development of a variety of dust collectors has made it possible to control the fly ash problems.

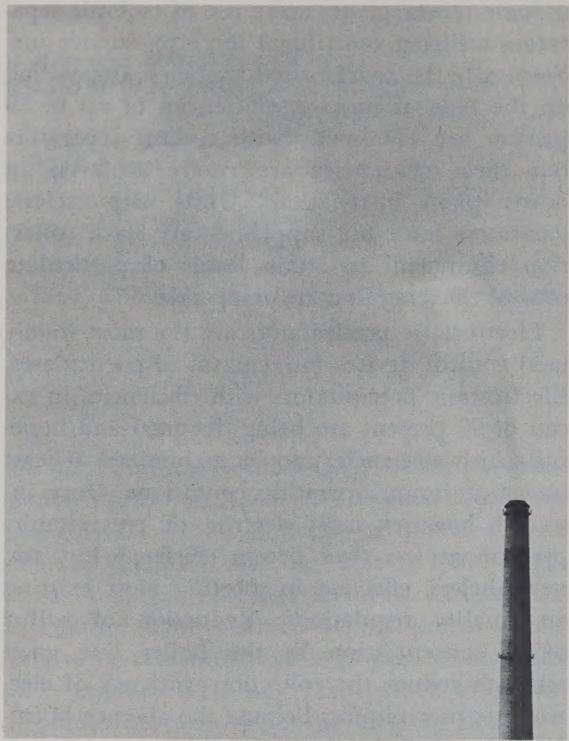
There are two general types of fly ash collecting equipment usually used in power plants: mechanical separators and electrostatic precipitators. Bag filters and wet scrubbers may also be used to remove particles and are in operation in some industrial establishments and a few power plants. Bag filters are not normally used in power plants because of high initial and operating costs. Wet scrubbers have high operating costs and require reheating of gases to provide buoyancy for good dispersion of stack effluents. Both bag filters and scrubbers need additional research and development to improve their prospects for solving the fine particulate problem.

Some power plants make use of cyclonic separators utilizing centrifugal force to remove mechanically the coarser-sized particles. Depending on the type of furnace, efficiencies of up to 80 percent are obtainable with cyclone separators but these efficiencies are rarely achieved in power plant installations. Units with cyclone separators must use supplementary stack collection equipment to attain levels of particulate control efficiency that are acceptable.

Electrostatic precipitators are the most widely used control devices for removal of particulates. Electrostatic precipitators with efficiencies in excess of 99 percent are being designed and hopefully such efficiencies can be maintained at least under optimum operating conditions. Once installed, however, most electrostatic precipitators perform at less than design efficiency but are, nevertheless, effective in meeting most existing air quality regulations. Reduction of sulfur oxide concentration in the boiler flue gases tends to reduce the collection efficiency of electrostatic precipitators because the absence of sulfur compounds increases the resistivity of fly ash particles. This causes concern when a power plant shifts to a low sulfur coal, unless coal ash levels are reduced simultaneously. Otherwise reduction in sulfur oxide emissions might be offset by an increase in particulates.

The costs of precipitators increase rapidly at the higher collection efficiencies. On a 500–800 megawatt plant, a precipitator of 95 percent efficiency may cost between $800 and $1,200 per megawatt; one of 99 percent efficiency may cost in excess of $2,500 per megawatt. The total installed cost may range up to 10 times this amount when precipitators are added to existing units.

The removal of fly ash from the flue gas creates the problem of fly ash disposal. As more efficient collection devices are developed and used, and as more coal-fired power plants are built, the total volume of ash for disposal will increase considerably. At the present time, there is a small market for ash. In 1968, approximately 24.6 million tons were produced, of which 5.2 million tons, or 21 percent, were utilized. The ash industry has been growing, especially since the formation of the National Ash Association, which is making attempts to develop new applications and increase ash sales to



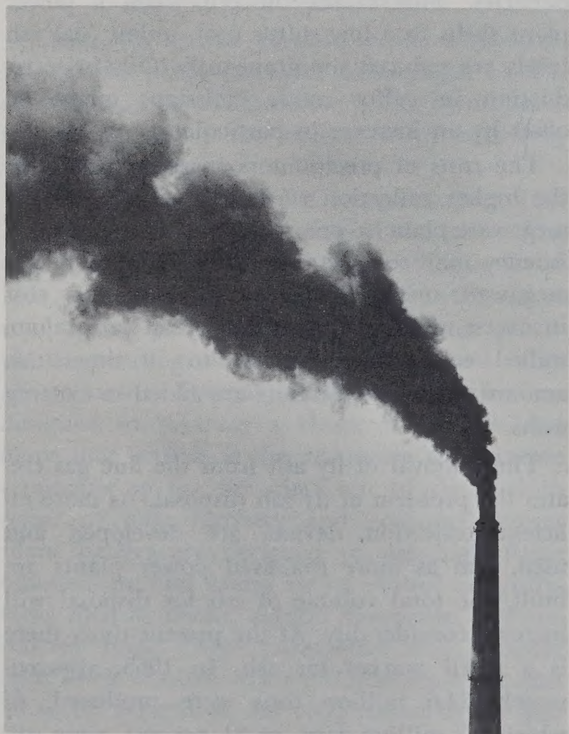


Figure 11.6—These two photographs show the effect of the electrostatic precipitators at Northern States Power Company's Allen King plant in Minneapolis, Minnesota. The precipitators were shut off momentarily for the picture showing the dark plume.

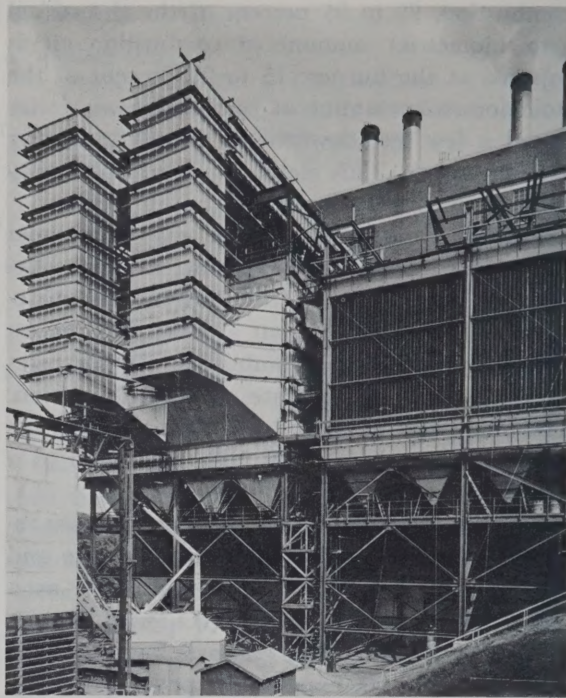


Figure 11.7—The effectiveness of emission control equipment is demonstrated in this photograph of Duke Power Company's Lee Steam-Electric Station. New electrostatic precipitators were recently installed on the units at left, while the units at right are equipped with older precipitators.

help reduce the problem and expense of ash disposal.

Dispersion by Tall Stacks

Tall stacks, here defined as stacks over 500 feet high, do not reduce overall emissions, but help disperse the effluent over a wider area. Surface-based atmospheric inversions, which restrict plume rise and pollutant dispersion, frequently extend from ground level up to 1,000 feet. Tall stacks, aided by thermal buoyancy, usually carry effluents above such inversion layers, so that they do not add to the pollution levels below the inversion. Peak ground level concentrations from tall stacks are usually noticeably lower than concentrations from short stacks.

Subsidence inversions act as lids to the upward dispersion of pollutants and may persist for extended periods. These inversions generally have their base or lid as low as 1,500 to 2,000 feet in the Los Angeles area and several thousand feet elsewhere. Effluents from tall stacks often cannot penetrate subsidence inversion lids

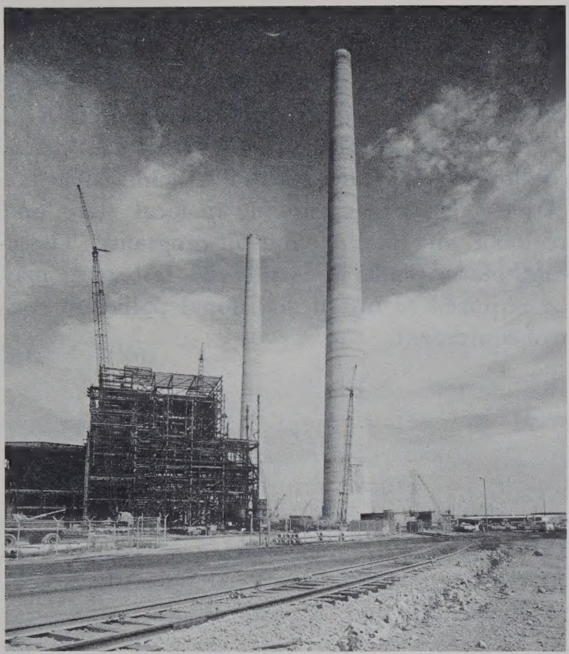


Figure 11.8—These two, 800-foot high stacks, will serve four units at Detroit Edison Company's Monroe power plant. When all four units are operating in 1973, the total generating capacity will be 3,200 megawatts.

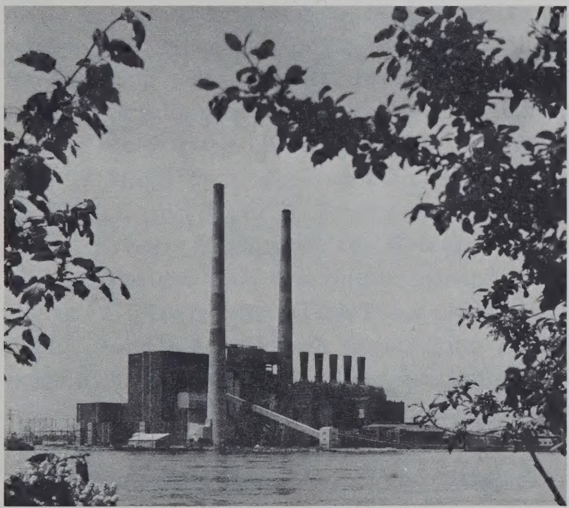


Figure 11.9—Detroit Edison Company's Trenton Channel power plant has 563-foot high stacks for its newer units built in the 1960's. Note the difference in these and the much lower stacks of units built in the 1920's.

and, consequently, may be trapped and brought to earth, increasing ground level pollution concentrations.

An additional aspect of tall stacks is their esthetic impact on the surroundings. The trend to larger power plants makes construction of tall stacks more feasible, but it also causes an increase in total emissions. More research is needed and is being carried out to determine the extent to which tall stacks improve local air quality under various meteorological and topographical conditions. TVA has conducted extensive studies in the Tennessee Valley region on dispersion of power plant emissions from tall stacks. The Air Pollution Control Office of EPA is currently studying the effects of tall stacks at electric power plants in Pennsylvania.

The British have tried a technique of clustering stacks (figure 11.10) into one tower to take advantage of the increased plume rise and inversion penetrating capability that results from massing the gas flow and reducing the cooling rate. This method increases the effective height of the stack and can reduce the unit costs of construction. A similar technique has been used extensively in Japan.

In designing power plant stacks and emission control equipment mathematical model studies can help achieve permissible pollution levels with the least overall costs. Parameters related to fuel, furnace type, combustion process, stack height and exit diameter, stack gas temperature,

MULTIPLE FLUE SMOKESTACK

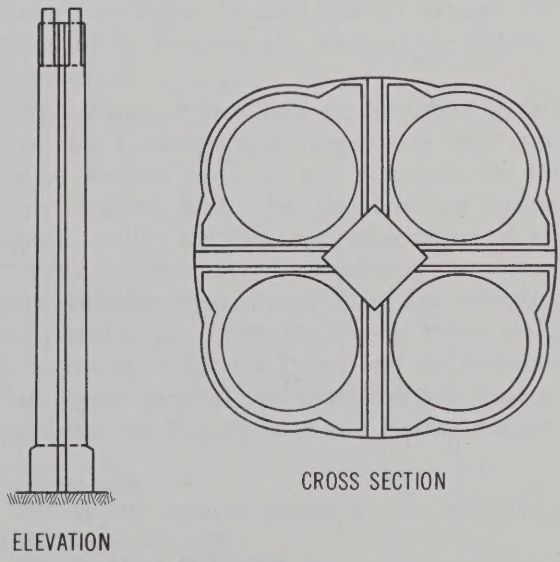


Figure 11.10

air pollution control devices, local meteorology and topography, coupled with mathematical formulas of plume rise and diffusion, can be used to approximate ground level concentrations. By varying stack heights and emission control methods the most economical way to obtain required control can be determined.

Tall stacks may cost from $1,000 to $3,000 per foot of height depending on foundation conditions, materials costs, and remoteness of plant site. Compared to low stacks they provide an extremely valuable means for reducing average annual ground level concentrations of stack effluents. However, it does not appear that they can provide the degree of control required in all places under a wide variety of meteorological conditions to assure consistent achievement of SO_2 standards now evolving in local, state, and regional air quality control programs. Therefore, power plants designed with tall stacks may be required to install additional pollution control equipment.

CHAPTER 12

ESTHETICS AND LAND USE OF POWER FACILITIES

Introduction

Rapid expansion of industrialization and urbanization in the United States has been achieved, in most cases, with insufficient regard for preservation of natural beauty and protection of the environment. Primary emphasis has been placed on rapid and low-cost production. During the past few years, however, numerous private and public groups and individuals at the Federal, State, and local levels have expressed a real concern about the quality of the Nation's natural resources and the appearance of the cities and countryside.

The White House Conference on Natural Beauty in 1965 served to focus national attention on the environment, and, subsequently, many important actions have been taken to establish and strengthen procedures and criteria for handling environmental problems. An important development from the White House Conference was the establishment by the President, in May 1966, of the President's Council on Recreation and Natural Beauty and the Citizen's Advisory Committee on Recreation and Natural Beauty. That Committee, assisted by an Electric Utility Industry Task Force on Environment, issued a report with far-reaching recommendations. The Task Force consisted of several officials of investor-owned utilities, management representatives of publicly owned utilities, a telephone company representative, and members of State regulatory commissions.

In 1968 the President's Council on Recreation and Natural Beauty published a report entitled "From Sea to Shining Sea," and the Task Force of the Citizen's Advisory Committee prepared a report on "The Electric Utility Industry and the Environment." Late in the same year, the Council's Working Committee on Utilities reported to the Vice President and to the President's Council on Recreation and Natural Beauty on actions needed to minimize the impact of necessary utility facilities on the quality of the Nation's environment. The Working Committee's report included guidelines for the protection of natural, historic, scenic, and recreational values in the design and location of rights-of-way and transmission facilities.

Executive Order No. 11472 [1], dated May 29, 1969, replaced the Council on Recreation and Natural Beauty with a new cabinet-level Environmental Quality Council. The National Environmental Policy Act of 1969 [2] included provisions for establishing a three-man Council on Environmental Quality within the Executive Office of the President.

In another Executive Order, dated March 5, 1970 [3], the President set out the general duties of Federal agencies and the specific responsibilities of the Council on Environmental Quality, changed the name of the Environmental Quality Council to the Cabinet Committee on the Environment, and designated the Chairman of the Council on Environmental Quality to assist the President in directing the work of the Cabinet Committee.

The Energy Policy Staff of the Office of Science and Technology, in cooperation with concerned Federal agencies, has prepared two reports dealing with the problems of siting electric utility facilities, including those of esthetics and land use. The report on Considerations Affecting Steam Power Plant Site Selection was issued in late 1968. The Energy Policy Staff, in its report on Electric Power and the Environment issued in 1970, recommended new Federal legislation relating to State and Federal respon-

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[1] 34 FR 8693.

[2] PL 91–190, approved January 1, 1970, 42 U.S.C.A. § 4321 et seq. (1971 supp.).

[3] EO No. 11514, 46 FR 4247.

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sibilities for preconstruction review and approval of bulk power facilities.

In 1970, the Environmental Protection Agency (EPA) was established as a new independent Federal agency which has been assigned broad responsibilities relating to all aspects of man's environment, as discussed in chapter 11.

Actions have recently been taken at other levels of Government and by industry to lessen the impact of power facilities on the environment. Several states have enacted or are considering legislation dealing with esthetics, and some states and local bodies have taken action relating specifically to the esthetics of utility facilities, as discussed later in this chapter.

The electric utility industry has made studies and is carrying on considerable research in the field of esthetics. In the fall of 1969, an industry-wide Electric Power Council on Environment was established, and one of its committees deals with esthetic problems. Most electric utility companies have, during the past few years, made significant strides in improving the appearance of facilities and in developing property for multiple uses.

By Order No. 414, which became effective January 1, 1971, the Federal Power Commission adopted new regulations implementing procedures for the protection and enhancement of esthetic and related values in the design, location, construction, and operation of licensed hydroelectric project works. At the same time, the Commission issued a set of guidelines for the protection of natural, historic, scenic, and recreational values in the design and location of rights-of-way and transmission facilities. The new regulations require applications for hydroelectric licenses to include an exhibit describing the architectural design, landscaping, and other reasonable treatment to be given project works, including compliance with the guidelines which accompanied the order. The applicant is to prepare this exhibit on the basis of studies made after consultation with, or consideration of comments submitted by, Federal, State, and local agencies or organizations and individuals having an interest in the natural, historic, and scenic values of the project area.

Achievement of esthetic objectives in the design and construction of electric power facilities cannot be accomplished by any single revolutionary breakthrough because the technical and economic problems are simply too big and complex. For some facilities such as distribution lines in new residential areas, progress toward esthetic objectives has been quite rapid, primarily because of more extensive use of undergrounding. For other facilities, such as high voltage transmission lines, esthetic improvements through undergrounding will be more difficult because of high costs and unsolved technical problems. Other alternatives, however, such as improved design, location, and land use practices, are effective to some degree in minimizing adverse effects. Additional research could aid materially in achieving esthetic objectives.

The national objective of improving the quality of the environment for the benefit of present and future generations and the concurrent rapid growth in demand for electrical energy make it apparent that improving the appearance of power facilities and preserving scenic and related values have become increasingly significant in electric utility programs. An important factor in reaching decisions on esthetic improvement is the relationship between the cost of improvements and the economics of power production, transmission, and distribution. The general public needs to be made aware of the opportunities, problems, and costs involved, and its representatives should be given the opportunity and the responsibility for helping to obtain a balance between environmental impact and cost of power. For example, state and regional land use plans, supported by adequate authority for their implementation, can help utilities identify acceptable sites for power facilities.

The various components of electric utility systems—distribution, transmission, and generation—present different visual problems and widely differing opportunities for esthetic improvements. Some solutions are easy and economical and some will be difficult at any cost. Each component is, therefore, discussed separately.

Distribution Facilities

Distribution facilities are widely dispersed and, therefore, constitute an extensive source of concern. However, of all electric facilities they are the most amenable to esthetic improvement.

Overhead Distribution Lines

Many unsightly overhead distribution lines with multiple crossarms, numerous wires, and

conspicuous appurtenances are visible throughout the Nation and a few cities condone construction and operation of dual electric systems by competing utilities, thus compounding the clutter in streets and alleys. The primary design criteria for older existing lines was reliable performance at minimum cost. Appearance was usually a secondary consideration. In response to increasing interest in the environment, utilities and manufacturers have developed many new designs, materials, and concepts to improve the appearance of overhead facilities.

A basic approach has been to reduce or eliminate clutter. This includes minimizing the number of conductors on each pole, eliminating crossarms as shown in figure 12.1, utilizing low profile transformers, and using appurtenances of improved design. In some areas, concrete, steel, or specially formed wood poles in various shapes are being used in lieu of conventional wood poles. A typical example is shown in figure 12.2. Fiber glass components in attractive shapes have become available for use in lieu of some of the hardware and supports formerly used.

In addition to simplicity of design, color of components has received attention. Where appropriate, insulators, transformers, poles, and other equipment used in new construction have colors that blend well with the surroundings.

Careful route selection for distribution lines may permit greater use of natural screening and help to soften or avoid the harsh silhouette. In some locations, construction of lines along the rear of property boundaries is a practical way of obtaining screening. Considerable improvement in appearance is being obtained in some high density residential areas by burying the service-conductors that run from the street to the house, particularly where the houses are closely spaced and where service conductors cross the street.

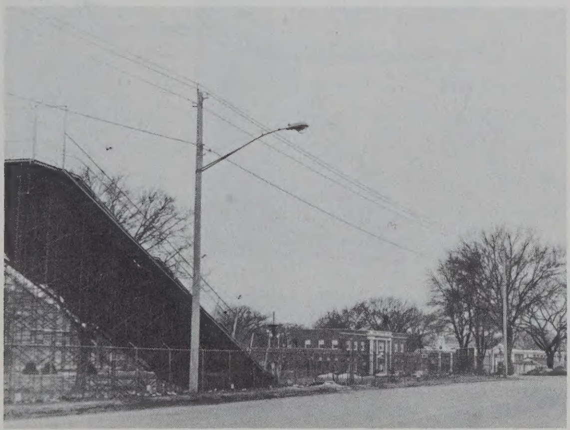


Figure 12.1—Clutter associated with distribution lines can be reduced significantly by eliminating the crossarms.

Figure 12.2—Specially designed poles for street and highway lighting help maintain the natural appearance often associated with secondary roads.

Underground Distribution Lines

Underground construction is the solution usually proposed by objectors to the appearance of overhead distribution lines. Generally, such construction is technically feasible since the relatively low voltage insulation problems are not critical and cable charging currents are not excessive. Underground installations greatly improve the appearance of an area, as shown in figure 12.3.

In recent years, lower cost underground distribution installations using directly buried cable, often placed in a common trench with telephone cables, have been developed and the use of such installations is expanding rapidly, particularly in new residential subdivisions, apart-

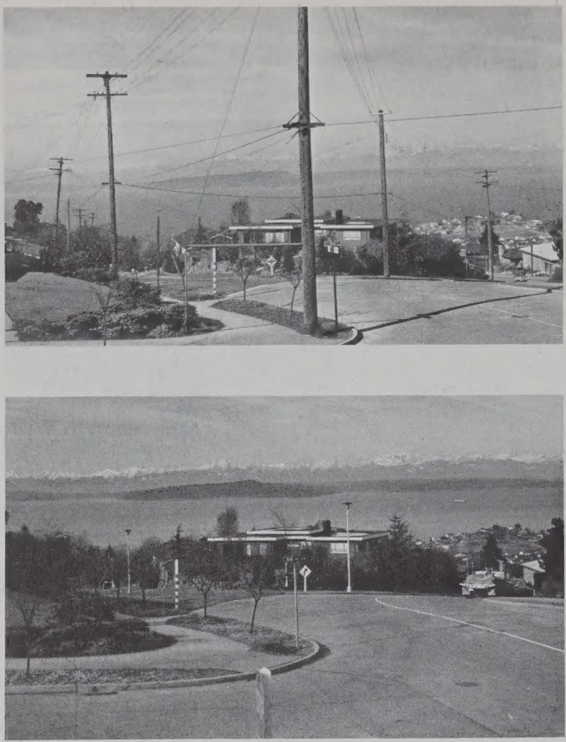


Figure 12.3—Undergrounding of distribution facilities in Seattle City Light's system improves a scenic view.

ment developments, and shopping centers. Also, subterranean transformers in the 15-kilovolt class, or low profile pad-mounted transformers, screened to conform to the landscape, are being used in new residential areas. The large pad-mounted units required for apartments and commercial installations can be located, painted, and architecturally treated so that they appear as a part of the planned development, as shown in figure 12.4.

The only visual evidence of transformers installed in underground enclosures is a grating required for ventilation and access to the transformer. Designs now being perfected will provide system components that can be buried without the necessity for gratings. However, operation and maintenance problems, including corrosion control, make the use of subsurface transformers costly.

One obvious advantage of undergrounding is the virtual elimination of wind, ice, snow, and sleet storm damage, which can be devastating to overhead systems. Flood damages, on the other hand, are more severe for underground systems. Another advantage is the elimination of surface facilities, other than those required for street lighting, thus reducing the frequency of vehicular accidents, minimizing acts of vandalism, and eliminating the hazard of electrical shock from live wires which fall as a result of accidents or storms. It should be noted, however, that modern overhead construction involves the use of high-strength materials and insulated secondary conductors, thus minimizing storm damage and shock hazards.

Studies indicate that operation and maintenance expenses of underground distribution systems are higher than for equivalent overhead systems. Duct systems and manholes are a necessity for city street installations, and changes in the systems to accommodate load growth or other new conditions are expensive.

The Electric Utility Industry Task Force on Environment, reporting to the Citizen's Advisory Committee on Recreation and Natural Beauty, set a target date of 1975 for underground construction of electric distribution lines in all new residential areas, whereas the Council's Working Committee on Utilities recommended that the target date be set at January 1, 1973. Significant cost differentials and some types of ground conditions in some areas make it apparent that these goals for undergrounding distribution lines in new residential areas will not be easily achieved. It is estimated that only about 25 percent of new distribution lines constructed in 1969 were placed underground, although some

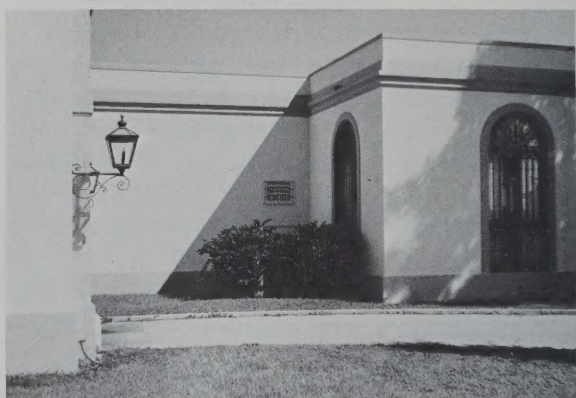


Figure 12.4—The recent practice of installing transformers on or below the ground is more conducive to natural screenings. The three phase 150-kVA pad-mounted transformer shown here behind the shrubbery serves the Museum of Fine Arts in St. Petersburg.

utilities reported that nearly 90 percent of new facilities were undergrounded during that year.

The Maryland Public Service Commission requires that all electric distribution lines for new residential buildings within a subdivision that has five or more building lots be undergrounded, and has prescribed the basis for cost sharing between the utility and the developer or owner. That Commission also requires that undergrounding be used for new distribution lines to commercial and industrial establishments, except for areas totally lacking in esthetic appeal. Many other states have expressed an interest in the Maryland actions, and similar requirements by other commissions are expected. For example, California's Public Utilities Commission has recently enacted comprehensive requirements on this subject, and the Illinois Commerce Commission has directed an Illinois utility to furnish underground service in new residential subdivisions without additional charge.

Conversion of Existing Overhead Distribution to Underground

Conversion of existing overhead distribution to underground is generally very costly. Conditions in developed areas are much less favorable for efficient underground construction. Elimination of existing overhead lines involves substantial costs in addition to those involved in undergrounding new distribution lines. Such added costs include undergrounding of telephone and municipal signal circuits usually hung on power line poles; providing poles and circuits for street lights; removal and replacement of street paving, sidewalks, and special landscape items; and rewiring the customers' service facilities. Furthermore, the undepreciated value of the overhead lines is lost. For these reasons, widespread conversion of existing overhead distribution is not anticipated within a forseeable timetable although such action would be esthetically desirable. The cost of converting overhead lines to underground is discussed in more detail in chapter 14.

Distribution Substations

To fulfill the ever-increasing electric energy requirements of the future, many additional distribution substations will be required. Considerable attention is being given to the location, design, and appearance of these installations to strive for environmental compatibility. The techniques being used include:

(1) Proper site selection based on interdisciplinary analysis of the area.
(2) Simplified designs that minimize components and the silhouette.
(3) Reduction in height of structures and equipment.
(4) Use of equipment colors that harmonize with the surrounding environment.
(5) Use of colors to create esthetic effects.
(6) Artful landscaping (figure 12.5) and lighting.
(7) Interesting architectural treatment with panels, walls, or enclosures (figure 12.6).
(8) Use of underground runs for primary feeders to reduce overhead congestion in the immediate vicinity.
(9) Site setbacks and appropriate station arrangement and orientation to minimize visual impact.
(10) Development of landscaped, public rest spots in set-back areas.

In many instances, improvements in the appearance of both new and existing substations can be obtained at nominal cost. The use of extensive architectural treatment, such as complete enclosures, may or may not increase costs of new substations, depending on the siting conditions.

Considerable progress has been made in reducing transformer noise with the result that it is much quieter in the vicinity of new substations than at those installed several years ago.

Transmission Facilities

Transmission lines are the highways for transporting large blocks of electrical energy. They are the higher voltage lines interconnecting substations, generating stations, and adjacent electric utility systems. In the United States, voltage levels of transmission lines are 69,000 volts and higher except for a few lines that are operated in the range of 60,000 volts. A very high percentage of the transmission system consists of overhead lines. Underground construction costs of high voltage lines using currently available technology are many times those of overhead lines, and the extension of the present technology to extensive distances is not practicable.

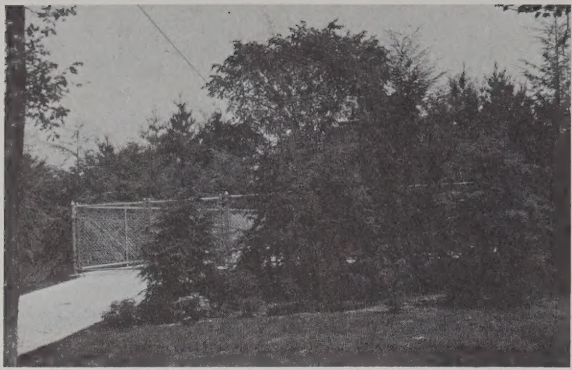


Figure 12.5—Plantings screen a distribution substation in Consolidated Edison Company's system.

Therefore, for the foreseeable future, undergrounding cannot now be considered economically feasible for general use, and most of the transmission system will continue to be overhead lines. Undergrounding will be limited principally to metropolitan areas and particularly scenic locations. A more detailed discussion of transmission patterns and costs is included in chapter 13.

Improvements in the appearance of overhead transmission facilities can be attained by proper route selection, strategic placement of towers, judicious right-of-way clearing, landscaping of rights-of-way, selection of more pleasing tower

Figure 12.6—Pacific Gas and Electric Company's alpine substation achieves environmental compatibility.

designs, use of compatible colors, and improved design of substations.

Overhead Transmission Lines

Since overhead construction is expected to continue to be used for most new transmission lines, it is necessary to determine how best to build the needed facilities and at the same time protect environmental values.

The guidelines prepared by the Working Committee on Utilities, those accompanying FPC Order No. 414, and the 1970 Report of the Departments of the Interior and Agriculture on Environmental Criteria for Transmission Systems include specific suggestions and sketches relating generally to the following:

(1) The selection and clearing of rights-of-way routes.

(2) The location of transmission structures and overhead lines.

(3) The design of transmission structures.

(4) The maintenance of transmission line rights-of-way.

(5) Possible secondary uses of rights-of-way.

(6) The location of appurtenant above-ground facilities.

Major factors in the esthetic treatment of overhead transmission lines are the selection, treatment, and maintenance of rights-of-way. General criteria for selection and effective use of rights-of-way, as set forth in the above documents, include the following:

(1) Scenic, recreational, and historic areas should be avoided where possible. If such avoidance is not possible, the rights-of-way should be located in corridors least visible from areas of public view.

(2) Heavily timbered areas, steep slopes, and proximity to main highways should be avoided where possible.

(3) Long views of transmission lines perpendicular to highways, down canyons and valleys, or up ridges and hills are particularly undesirable. The lines should approach and cross these areas diagnonally.

(4) Rights-of-way clearing should be limited to that absolutely essential, and the boundaries of cleared areas should be curved or undulating and trimmed to comport with the topography of the terrain.

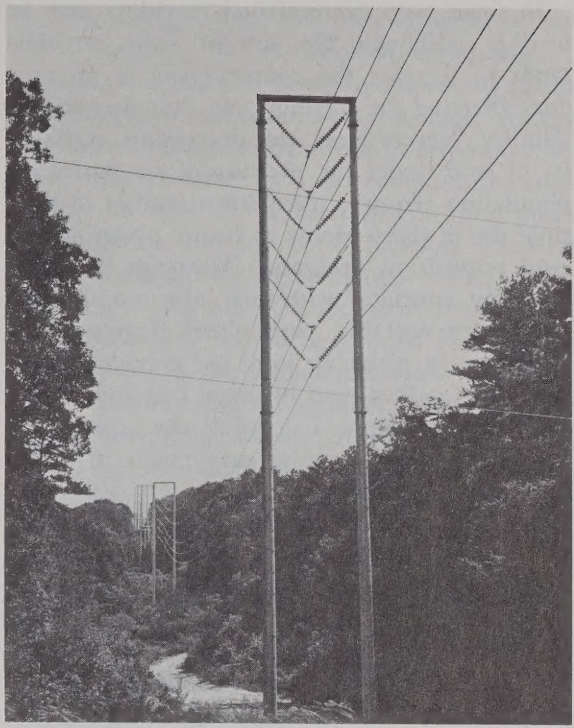


Figure 12.7—Location and landscaping were important factors in the design of this 230-kV transmission facility of Georgia Power Company near Atlanta.

(5) Small trees and plants should be used to feather the rights-of-way edges from grass to larger trees.

(6) Transmission facilities should be located with a background of topography and natural cover where possible.

(7) Vegetation and terrain should be used to screen facilities from highways and other areas of public view.

(8) Where access roads are required they should be curved or run diagonally across the right-of-way to minimize their visual impact.

Existing rights-of-way should be used, if feasible, for additional transmission facilities, and joint use by different kinds of facilities should be considered. The networks of railroad rights-of-way may provide opportunity for power transmission, either with or without railroad electrification, if technological problems such as inductive interference with railroad signal and communication circuits can be solved.

In some cases, transmission corridors may be feasible, although the use of such corridors tends to increase the consequences of an accident affecting the corridor, and thus decrease reliability. Nevertheless, the decreasing availability of land under the pressure of an expanding population requires increased attention to multiple use of rights-of-way in future planning and land acquisition programs. Although there are problems associated with such joint use, they are not insurmountable, particularly if given early attention. In planning joint use corridors, environmental values must be given full and careful consideration, since increasing the amount of land in a single corridor may result in severe concealment problems.

In many cases, transmission line rights-of-way can be used for unrelated secondary purposes. Possible uses include: cultivation of Christmas trees and other nursery stock; gardening, general agriculture, and pasture; planting for wildlife food and cover; and various recreational purposes such as hiking trails, bicycle paths, snowmobile routes, and picnic areas. These uses, under proper conditions, have both economic and environmental advantages, and the fact that they are permitted may create a goodwill benefit for the utility.

In addition to rights-of-way considerations, an important factor in improving the appearance of overhead transmission facilities is the design of transmission structures. Pertinent factors in selecting the appropriate design are the environment of the area and the degree of visual exposure involved. Conventional towers are tapered lattice structures, designed to support one or more circuits of bare copper or aluminum conductors attached to porcelain insulators. The tower structures, usually of steel construction, have high strength and stability, thus permitting the greatest possible distance between towers. Another lattice type structure is the guyed-V or guyed-Y, which has the main body of the structure supported at a single point with the tops held in place by guy wires.

Wood poles have also been used extensively for transmission structures because wood is frequently more economical than metal. The predominant types of wood structures are H-frames and single poles. The limited strength of wood makes it necessary to use relatively short spans in comparison with steel structures. However, shorter spans often permit a narrower right-of-way because reduced wire sag results in less swing caused by strong winds.

In a 1967 study entitled "Electric Transmission Structures," sponsored by the Electric Research Council and the Edison Electric Institute, the industrial designer, Henry Dreyfuss, developed a number of structural variations for transmission towers. The designs fall into two principal categories: wide base with two or four legs, and narrow base with a single supporting stem.

The use of tapered steel poles rather than conventional towers has in a number of cases improved the appearance of the right-of-way, as shown in figure 12.8. With crossarms of pleasing shapes, the pole structures present a clean, uncluttered appearance. A disadvantage is that these poles require substantially more steel than towers, and thus are more expensive, but overhead lines using them cost much less than underground transmission facilities.

In addition to steel, laminated wood and concrete have had limited use for transmission pole construction. Other materials, such as reinforced plastic, are also possible.

Materials used to construct transmission structures, and the colors of the components, should harmonize, to the extent possible, with the natural surroundings. For example, treated wood poles are less obstrusive in forest or timber areas and weathered galvanized steel is the least apparent when the structures must be silhouetted against the sky. Painted transmission poles have been used successfully to blend struc-

Figure 12.8—The use of ornamental poles by Commonwealth Edison Company improves the appearance of an overhead transmission facility in the Chicago area.

tures with the landscape. Some utilities are developing color standards that provide for coordinated color treatment of transmission and substation facilities.

Considerable work has been done to improve the esthetics of overhead transmission facilities; however, there is still a need for additional improvement.

Underground Transmission Lines

In 1970, there were about 2,000 miles of underground transmission lines in the United States, mostly in densely populated areas where overhead rights-of-way are not available or are prohibitively expensive. These high voltage underground lines represent less than one percent of the Nation's total transmission system.

From an esthetic point of view, the underground construction of transmission facilities might seem to be desirable. In wooded areas, however, undergrounding would require a completely cleared swath. Moreover, the earth disruption of burial could heighten erosion, and under certain soil and moisture conditions the heat dissipated into the earth by underground conductors could adversely affect vegetative growth. In such areas, the visual impact of undergrounding could be as pronounced as for overhead installations.

Another esthetic consideration in undergrounding alternating current transmission lines is the bulky equipment required to compensate for charging current (see chapter 13). Providing such equipment along the underground transmission lines creates siting problems comparable to those involved in locating and designing substations.

Fewer technical and environmental problems are encountered in undergrounding direct current transmission lines than for alternating current systems. However, esthetics must be an important consideration in designing and locating the expensive converter equipment required to change from alternating to direct current at the sending end and to change back to alternating current at the receiving end.

Transmission Substations

Substations associated with the transmission of bulk power supplies are necessarily larger than those included in distribution systems. The techniques for environmental compatibility are similar, except that full concealment is not usually possible for transmission substations.

Substation location is vitally important as the concentration and confluence of high voltage and lower voltage distribution lines create a severe impact on the area and communities adjacent to the site. The substation is a focal point of congestion and its proper location is one of the most important elements of a utility's environmental program. Colors, structural design, and landscaping should be selected to accent or be accented by the natural elements and forms of the surrounding environment. Simplicity of design, including components with low profile, should be considered essential, and lighting frequently can be used to enhance the appearance of substations.

Maintenance, warehouse, and storage facilities at substations should be so located and maintained as to minimize their effect upon the environment.

Generating Facilities

The opportunities for improving the appearance of electric generating stations vary substantially with the type of plant, as discussed in the separate sections that follow. Much has been and is being done by utilities to improve the appearance of generating stations. Additional discussions relating to generating facilities are in chapters 5, 6, 7, and 8.

Hydroelectric Plants

The topography, geology, and other site conditions of the region generally determine not

Figure 12.9—An ornamental wall and shade trees are featured in landscaping Dallas Power and Light Company's 138-kV Matilda substation in Dallas.

only the location of a hydroelectric project but also the type of major structures such as the dam, spillway, and outlet facilities, that are required. Once the general plan is established, however, there are a number of opportunities for esthetic treatment.

In the case of massive concrete structures, there are opportunities for architectural treatment of the facilities so as to present an attractive and coordinated design for the entire project. For best results all design professions must work together to achieve a unified design. The designers must also work in close cooperation with the contractor to assure the preservation of natural features and provide compatibility between the structures and the surrounding landscape. Good examples of what can be achieved with such an approach are the Corps of Engineers' Libby project in Montana, the Bureau of Reclamation's third power plant at the Grand Coulee Project, and the City of Seattle's Ross Dam in Washington.

For projects including large embankments, the appearance can be improved by landscaping. Ridge lines need not be uniformly straight, and they may include some undulations. Landscaping along the crest and the toe of embankments can blend them with their surroundings. Graded plantings and grasses can be utilized to conceal the scars of construction and of fluctuating water levels.

When a powerhouse is located at a dam, it should be designed to harmonize with the dam design. At the Libby project the powerhouse configuration is integrated with the downstream face of the dam (figure 12.10). In some cases, the underground construction of powerhouses will eliminate landscape intrusions. An example is the powerhouse of the 1,000-megawatt Northfield Mountain pumped storage project, now under construction by Northeast Utilities in Massachusetts, which will be several hundred feet underground. Project facilities above ground will be integrated with the landscape. At the Bureau of Reclamation's Yellowtail and Morrow Point dam and power plant installations, transmission lines in the vicinity of the plants have been undergrounded and the Morrow Point plant itself has also been built underground.

Hydroelectric projects tend to attract large numbers of visitors. Therefore, parking space,

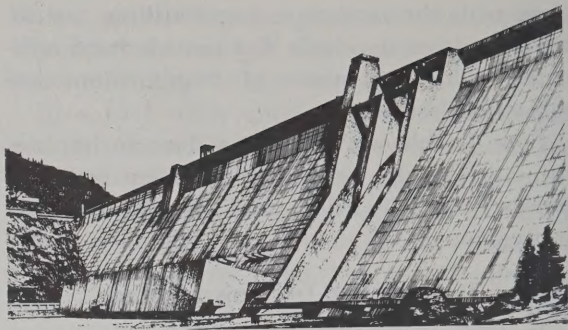


Figure 12.10—Corps of Engineers' Libby Dam and Powerhouse.

visitors' centers, and other facilities should be provided to take care of the visiting public. The design of these facilities should conform to the overall design of the project. Recreational use of the land and waters of a project also requires facilities, which should be designed, operated, and maintained, to the extent possible, to blend with, preserve, and enhance the natural landscape.

Steam-Electric Plants

Although generally more flexible than the selection of hydroelectric plant sites, the selection of the sites for steam-electric plants involves consideration of such factors as economy, the availability of cooling water and fuel, safety, reliability of service, environmental effects, and esthetics. Obviously, sites selected for steam-electric plants must be consistent with state, regional, and local land use plans and zoning regulations. Until recently, environmental effects and esthetics were given only secondary consideration in selecting many plant sites. The industry now generally recognizes the need to improve the appearance of its facilities and reduce environmental impacts. In order to gain full public acceptance, the trend toward environmental improvement needs to be broadened and expedited.

The location and design of facilities on a selected site are important factors in minimizing the impact on the natural environment. Appearance can be enhanced by the establishment of buffer zones around the plant. These zones, which should be considered by regulatory bodies as integral parts of the site, can be used to screen the plant facilities by means of trees, veg-

etation, and other landscaping. In many cases, picnic areas can be provided, and the addition of artfully designed visitor centers at power plants can improve public acceptance of the facilities. It is important also that transmission lines extending from the plant be visually acceptable.

Both nuclear and fossil-fueled steam-electric plants include large buildings and other structures, and fossil plants often include very tall stacks. The esthetics of power plants are enhanced by good architectural design and landscaping treatment. Strategic profiling and positioning of buildings and structures, use of appropriate materials and colors, and use of screening and blending of landscaping are among the techniques available to moderate visual impact. Even the stacks, which are difficult to treat esthetically, can be designed, located, and colored to complement other structures. Outside lighting may also be used to improve plant appearance.

Substantial improvements can be made in the appearance of fossil-fueled plants. Coal-burning plants in particular can be upgraded by improved designs for coal storage facilities. Use of retaining walls and additional conveyors would permit trimmer and smaller coal yards and thus reduce the random appearance of such areas at many existing plants. Landscaping of coal yards and ash disposal areas would also improve the appearance, and fuel transportation facilities can be given appropriate esthetic treatment.

The type of cooling system used greatly influences the esthetic qualities of steam-electric plants. Once-through systems usually cause the least noticeable change in the natural environment. The required structures include an intake with screens, a conduit or canal leading to the condensers, a discharge conduit or canal, and possibly a dispersion outlet. These rather modest structures are normally located at the edge of a water body with a major part of the installation being placed underground or underwater. However, care must be taken to assure that the warm water discharges will not adversely affect the ecology or appearance of the water source.

Cooling ponds are more expensive than the normal once-through systems but the structural requirements are essentially the same. Cooling ponds may add to the beauty of an area and provide recreational opportunities, but the addition of heat to the water in cooling ponds accelerates the rate of evaporation which has some effect on the humidity of the local area, possibly increasing the amount of fogging. Also, favorable sites for the ponds may not be available, particularly in urban areas.

Cooling towers, whether of the mechanical or natural draft type, are large structures which have a great visual and environmental impact. Because of the sizes of structures, cooling towers are difficult to treat esthetically. However, good structural design of facilities and landscaping of the site are helping in maintaining an acceptable appearance and minimizing disharmonies with the natural environment. Also, the plumes of visible water vapor that vary in volume and length with changing weather conditions must be considered and evaluated in selecting the type of cooling tower and site location. Ground-level effects upon local weather, including fogging or icing, tend to be greater for the mechanical draft type owing to its lower height.

If dry cooling is utilized, the required structures would create somewhat greater visual impacts. Both the mechanical and natural draft structures would be larger in size or of greater number than evaporative cooling towers. However, the adverse esthetic impacts would be offset to some degree by the absence of any visible plume.

Despite the greater cooling needs, nuclear plants have better opportunities for esthetic treatment than fossil-fueled plants. The nuclear plants are cleaner, eliminate the need for extremely tall stacks, do not require large fuel storage areas or ash disposal areas, and significantly reduce the required transportation of fuels and wastes. Thus, they can be more readily harmonized with the surrounding landscape. From the layout of the planned Trojan plant on the Columbia River (figure 12.11) it is clear that a cooling tower is a very difficult facility at nuclear plants to treat esthetically.

Esthetically, nuclear plants are well-suited to urban siting, assuming a source of cooling water is available. Urban locations may become commonplace after a longer period of operating experience demonstrates their safety and reliablity. Load center locations would permit elimination of some transmission facilities and their associated esthetic problems. Presently, however, nuclear plants are being located in rural set-

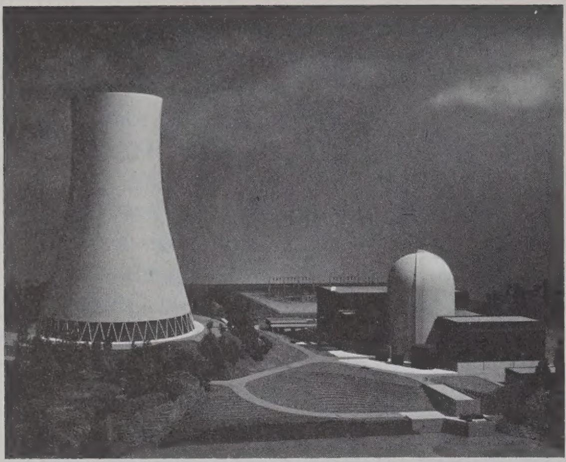


Figure 12.11—The proposed layout for Portland General Electric Company's 1,130-MW Trojan nuclear plant near Portland, Oregon.

tings, and this practice will probably continue for the immediate future. With proper design, such sites can provide areas and facilities for parks and recreation areas, wildlife preserves, and encampments for scouting or other groups. Some consideration is being given to building nuclear plants underground to enhance safety and public acceptance.

Gas Turbine and Internal Combustion Plants

Because of their relatively small size, gas turbine and internal combustion plants are readily adaptable to esthetic treatment. Since such plants do not require large quantities of cooling water, there is greater flexibility in their location than for other types of generating plants. Gas turbine and internal combustion plants are sometimes placed partially or totally underground to reduce plant noise. In areas where water bodies and water courses exist in close proximity to metropolitan areas, gas turbine plants can be mounted on barges.

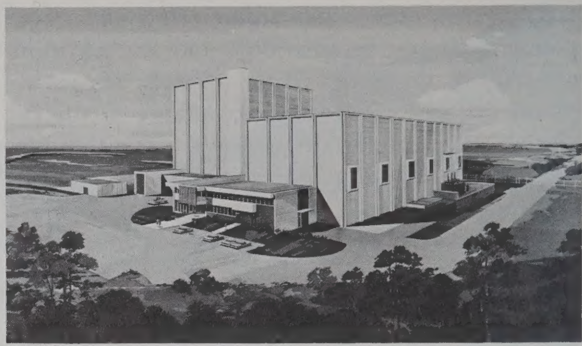


Figure 12.12—Design for Boston Edison Company's 625-MW Pilgrim nuclear plant at Plymouth, Massachusetts.

Esthetic treatment of gas turbine and internal combustion plants includes appropriate architectural design of buildings, color and texture selection of exterior walls, noise insulation, exterior lighting, and landscaping.

CHAPTER 13

TRANSMISSION AND INTERCONNECTION

Introduction

The need to transport electrical energy efficiently and economically from one location to another in ever increasing amounts has led to continual development of higher and higher transmission voltages. Virtually all transmission in the United States is by means of alternating current and the past decade has seen a rapid expansion in the use of 345 and 500-kilovolts ac as primary transmission levels. The first 765-kilovolts equipment in the United States was energized in the spring of 1969. The first extra high voltage (EHV) dc installation in the United States, a ±400-kilovolts system reaching from northern Oregon to southern California, was placed in commercial service in May 1970. The trend to higher voltages, accelerated in the past primarily by the economic advantages of transmitting large blocks of power, is now influenced significantly by the need to make maximum use of rights-of-way and thereby to minimize the environmental intrusion.

A fundamental approach to achieving reliable power supply requires that extensive transmission systems operate as integral parts of a strongly interconnected network. Three principal objectives in providing adequate interconnection transmission capacity [1] are:

"1. To support immediately any load area suddenly faced with a serious and unexpected deficiency in its normal generating supply. The network must have capacity to handle, well within stable limits, the automatic inflow of supporting power from the hundreds of generators in the surrounding interconnected network.

2. To transfer, without serious restriction, capacity and energy within regions and between regions to meet power shortages. Emergencies can arise from innumerable causes, such as delays in commercial operation of new generation, problems with new equipment, the failure of major generating units or other elements of the system, and unexpected peak demands caused by weather extremes.

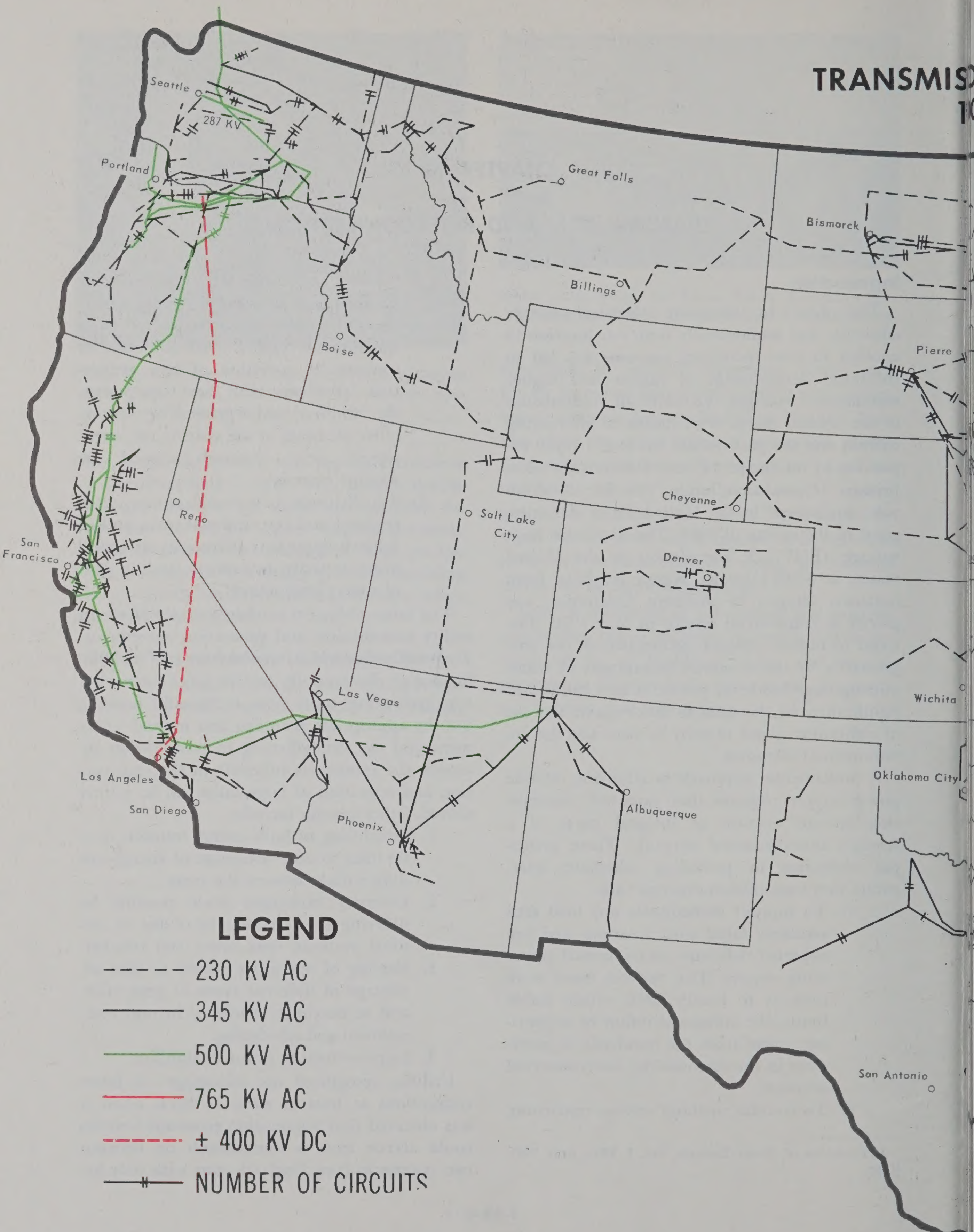
3. To exchange power and energy on a regional and interregional scale, and to achieve important reductions in generating capacity investment and in cost of energy production."

The latter objective is often a major factor in utility transmission and generation agreements. Frequently, individual systems are not able to finance or economically use the large steam-electric generating units now technically feasible, but, by appropriate planning and mutual agreement and the strengthening of transmission interties, the economies inherent in the construction and operation of large units can be jointly shared. Other benefits include:

1. Scheduling of bulk energy transfers over tie lines to take advantage of energy-cost differentials between the areas.
2. Diversity exchanges made possible by differing load characteristics due to seasonal patterns, time zones, and weather.
3. Sharing of operating reserve to take advantage of different types of generation and to maximize efficiency in unit commitment and scheduling.
4. Improvement in transient stability.

Utilities recognized the advantages of interconnections at least as early as 1914, when it was observed that appreciable economic benefits could accrue from a transmission tie between two systems in New England—one with only hy-

[1] Prevention of Power Failures, Vol. I, FPC, June 1967, p. 57.


TRANSMIS
1
Seattle
287 KV
Portland
Great Falls
Bismarck
Billings
Boise
Pierre
Reno
Salt Lake
City
Cheyenne
San
Francisco
Denver
Las Vegas
Wichita
Los Angeles
Oklahoma City
San Diego
Albuquerque
Phoenix
San Antonio
LEGEND
230 KV AC
345 KV AC
500 KV AC
765 KV AC
± 400 KV DC
NUMBER OF CIRCUITS

ON SYSTEM
0

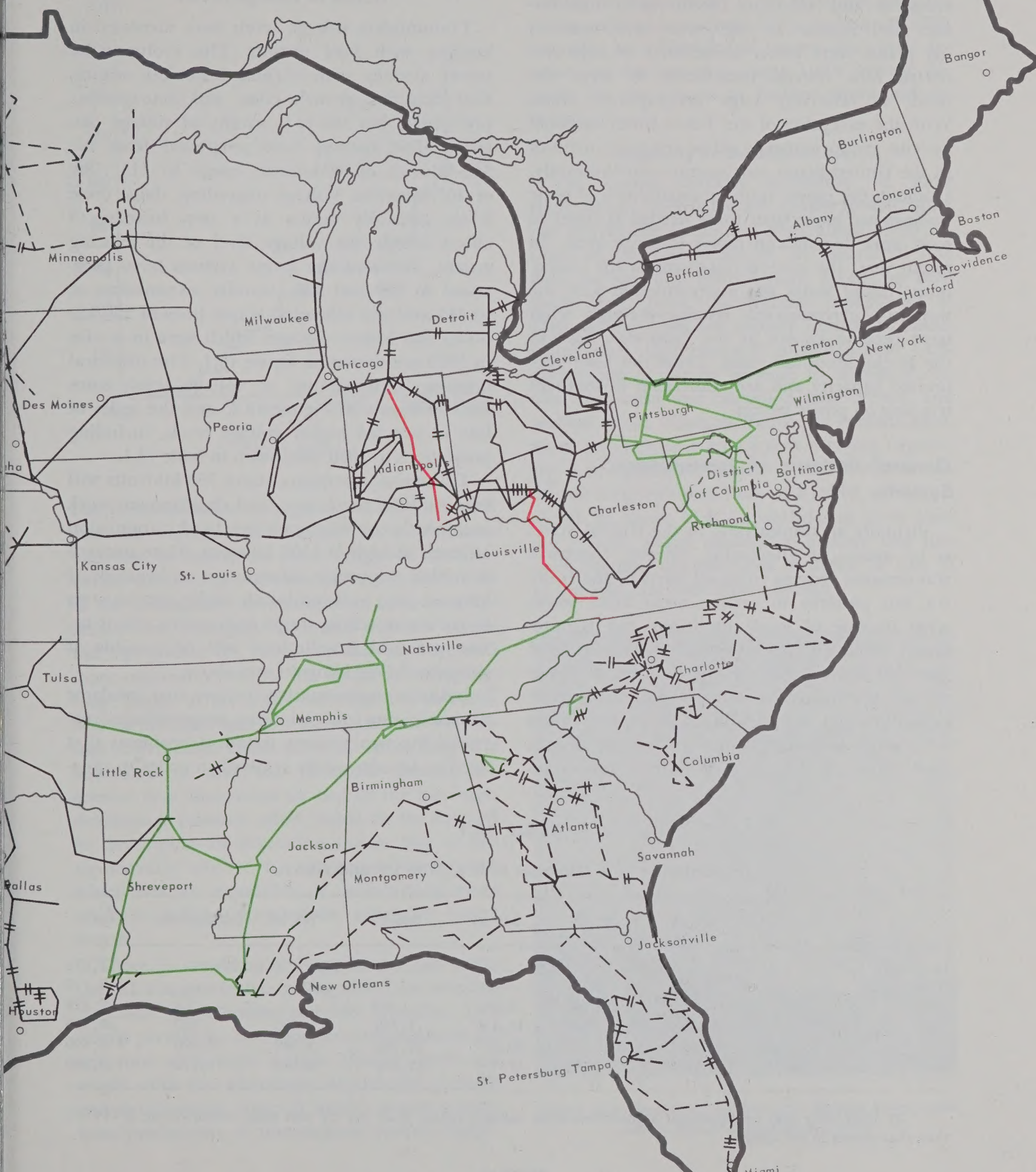


Figure 13.1

droelectric and the other with only steam-electric sources of generation. Elsewhere throughout the country, the rapidly improving transmission and generation technologies provided strong economic and reliability incentives to interconnect small systems. By 1920, many small generating plants were either abandoned or interconnected into systems established to serve the needs of relatively large geographical areas. With the exception of the Texas Interconnected Systems group, virtually all of the large utilities in the United States now operate synchronously, although the power transfer capabilities of some tie-lines are lower than those needed at times to meet peak demands in power shortage areas. In recent years the eastern two-thirds of the contiguous United States was interconnected with the western interconnected systems through what have become known as the "east-west ties" in the Rocky Mountain area. These ties have very limited capacity and are vulnerable to frequent tripping on power swings.

General Patterns of Transmission Systems

Virtually all transmission in the United States is by means of alternating current. Extensive transmission systems cover all parts of the country, but patterns in various areas differ somewhat because of local conditions and requirements. Some of the networks evolved, as load growth required, through the creation of higher voltage transmission overlays to provide greater capacity; some were developed as express routes for energy from generating stations to distant load centers; and some were built to provide interconnections between companies in pool groups, or ties between pools or other operating areas.

Trends in Voltage Levels

Transmission voltage levels have increased in keeping with load growth. The evolution of power systems with various historical origins, load densities, growth rates, and management preferences has led to a variety of voltage patterns. Most systems have progressed from the 34.5-kilovolt or 69-kilovolt range to 115, 138, or 161 kilovolts. Voltage upgrading above these levels generally occurs as a step increase to about double the voltage level of the existing system. Many of the larger systems have progressed to 230 and 500 kilovolts transmission or to 345 and 765 kilovolts. Major lines of 230 kilovolts and higher voltages which were in service in 1970 are shown on figure 13.1. The historical increase in maximum ac voltage levels since 1883 is shown in Figure 13.2, and the miles of line in selected higher voltage levels, including projections to 1990, are shown in table 13.1.

Transmission voltages above 765 kilovolts will be needed in the future, and development work is currently under way on overhead transmission at levels as high as 1500 kilovolts. More research is needed to provide information on behavior of long air gaps and insulation media and on ways to reduce switching surges and corona effects before practical installations will be possible at voltages of 1000 kilovolts and above.

Industry representatives believe that insulator contamination and switching surge voltages represent the two greatest technical problems that need to be adequately resolved in order to prog-

TABLE 13.1

Transmission Line Mileages in U.S., 230 kV and Above[1]

	230 kV	287 kV	345 kV	500 kV	765 kV	±400 kV(dc)	Total
1940	2,327	647					2,974
1950	7,383	791					8,174
1960	18,701	1,024	2,641	13			22,379
1970	40,600	1,020	15,180	7,220	500	850	65,370
1980	59,560	870	32,670	20,180	3,540	1,670	118,490
1990	67,180	560	47,450	33,400	8,940	1,670	159,200

[1] By 1990 there may be significant applications of ac voltages higher than 765 kV and more extensive use of HVDC than that shown in the table.

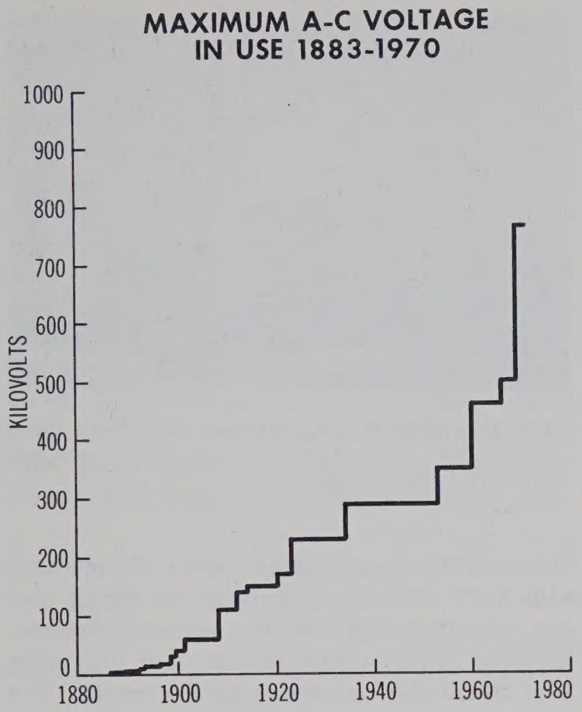


Figure 13.2

ress to transmission voltages above 765 kilovolts. Induced voltage and audible noise problems may also be difficult to solve. Insulator contamination interacting with moisture and pollutants in the atmosphere is one cause of flash-over. Insulators on overhead lines and outdoor terminal equipment are being exposed to more and more contamination. As the insulator strings become longer at the higher voltages, the contamination problem becomes worse because the voltage distribution across the total string length is less uniform and the dielectric stresses are greater near the conductor end of the insulator. Additional research effort needs to be devoted to developing an insulation system that is not significantly affected by contamination, or one which has the capability of maintaining more uniform voltage distribution across its entire length.

There is considerable support for the selection of a single future voltage level for overlaying both 500 kilovolts and 765 kilovolts. This would permit the development of equipment for only one ultra high voltage (UHV) level and would offer the advantages of reduced research and development costs. It would permit greater mass production of transmission system components, and more opportunities for interchange of parts and equipment required for maintenance by limiting the number of different system components. The disadvantage of the single overlay voltage concept is the relatively large capacity ratio of a uniform UHV system, say 1300 kilovolts, to a 500-kilovolt system. And final decision on the use of a single UHV voltage depends on the results of further study and research.

Capacity of Overhead Lines

The power transfer capability of most transmission lines is neither simple to determine nor convenient to state in generalized terms because of the interaction of an individual line with the network. Furthermore, except for relatively short lines, the transfer capabilities of high voltage lines are usually limited by something other than thermal considerations. Conductor size is usually selected to minimize corona loss, radio and television interference, and audible noise. Thus, it frequently exceeds minimum requirements for current carrying capability. A comparison of nominal load levels for relatively long overhead lines of selected voltages is shown in figure 13.4. Capabilities of short lines are greater. Surge impedance loading and line compensation are discussed in detail in Part II of the 1964 National Power Survey.

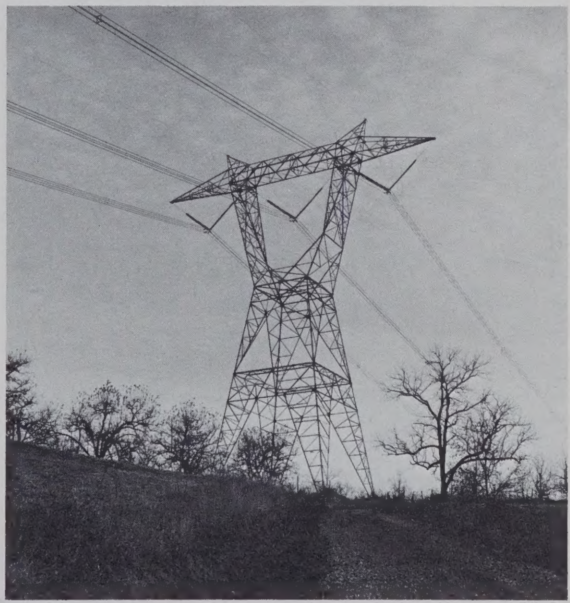


Figure 13.3—Steel tower on American Electric Power Company's 765-kV transmission system.

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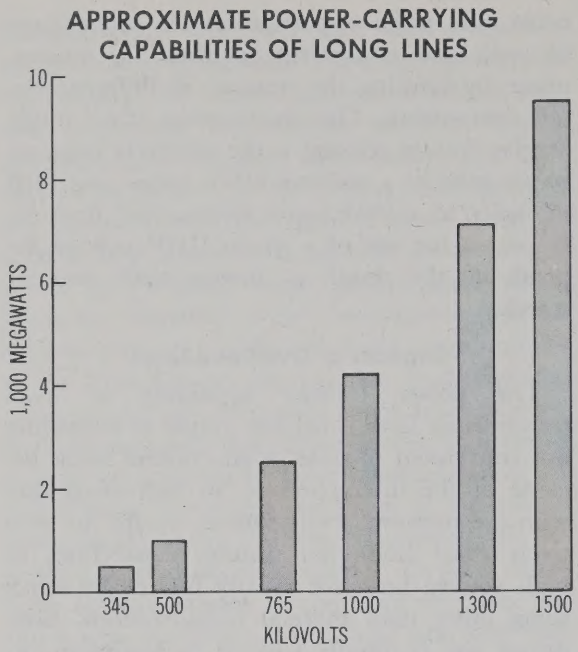

Figure 13.4

Transmission Line Cost Considerations

One of the important considerations in the design and costs of transmission systems is the maximum utilization of available rights-of-way.

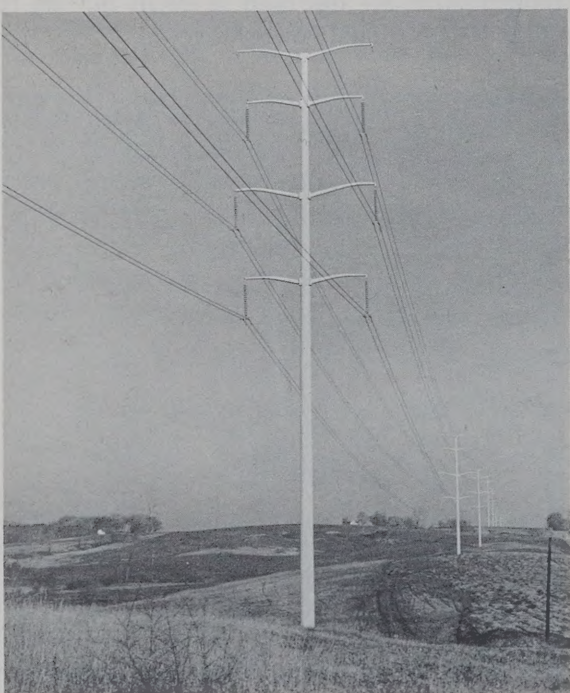

Figure 13.5—Modernistic structures support two 345-kV lines of the Northern States Power Company.

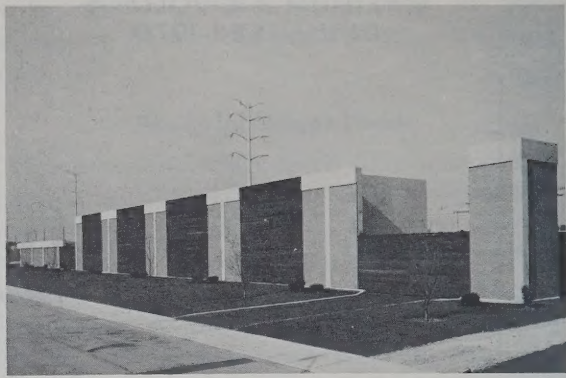

Figure 13.6—Chicago area substation and 138-kV transmission line of the Commonwealth Edison Company illustrate modern designs.

Many utilities have replaced lower voltage lines with EHV facilities to increase the power that can be transmitted over the same right-of-way. Multiple circuit configurations have also been used extensively to achieve similar results. The optimum transmission voltage for a particular circuit is, in part, determined by transmission distances, magnitudes of power to be transferred, network arrangements, terminal costs, environmental considerations and other related factors. All must be carefully considered in selecting the proper time to introduce additional lines or a higher transmission voltage on a given system.

Costs of rights-of-way and construction of new transmission lines vary widely depending upon terrain and competition for land. In some heavily populated areas, such as New York City, it is virtually impossible to construct overhead transmission lines, and the only means of transmission system expansion is through the use of underground circuits. As urban populations increase this condition will become more widespread.

The growing emphasis on environmental protection and aesthetic improvement is encouraging consideration of underground systems but, for the foreseeable future, more than 90 percent of the transmission system expansion outside of highly congested areas is expected to be overhead.

Changes in the design and construction of overhead transmission facilities to minimize environmental intrusion (see Chapter 12) will add to the cost of future lines and, consequently, increase the cost of energy to the ulti-

mate consumer, but such costs are generally much less than the cost of undergrounding.

Costs of transmission lines below 500 kilovolts, discussed in detail in the 1964 National Power Survey, have undergone no fundamental changes, but of course there have been considerable increases in costs of rights-of-way, labor, and materials. Cost information for transmission lines of 500 kilovolts and above was very limited in 1964, but construction since that time has provided cost data as shown in table 13.2. It is apparent that significant differences in costs occur even within the same general geographical area, due to differences in such things as labor costs, route conditions, rights-of-way acquisition costs, and the length of the line involved.

The cost per unit of energy transfer decreases with escalation of voltage levels, even though total capital costs increase, because the capacity of transmission lines in stability-limited systems increases approximately as the square of voltage, while total cost increases at a lower rate. In addition, the line losses per unit of capacity are usually less with higher voltages. Comparative resistance losses per 100 circuit miles of transmission distance are shown in figure 13.7 for typical EHV line designs now in service in the United States.

For a given distance and load, there is an optimum voltage which results in a minimum cost per kilowatt-hour transferred, as shown in figure 13.8. Similar charts could be prepared for other

TABLE 13.2

Actual Costs of Specific AC Lines

Conductors	Cost per Mile [1]		
	Right of Way and Clearing	Line Construction	Total
EASTERN AREA—500 kV			
2–2037 ACSR	$30,700	$80,800	$111,500
2–2493 ACAR	13,500	128,500	142,000
2–2049 5005	16,700	85,800	102,500
3– 971 ACSR	12,400	65,300	77,400
4– 583 ACSR	10,000	95,500	105,500
2–2032 ACSR	17,000	98,000	115,000
2–2490 ACAR	20,000	142,000	162,000
2–2490 ACAR	59,000	272,000	[2] 331,000
2–2500 ACAR	22,000	118,000	140,000
3– 954 ACSR	12,000	95,000	107,000
CENTRAL AREA—500 kV			
3– 954 ACSR		84,200	
3–1024 ACAR	24,000	95,600	119,600
WESTERN AREA—500 kV			
2–1780 ACSR	7,100	72,200	79,300
2–1852 ACSR		82,000	
2–2156 ACSR	25,000	93,900	118,900
2–2156 ACSR	2,000	124,000	[3] 126,000
ALL REGIONS—735–765 kV			
Average of 735 kV and 765 kV lines	18,700	146,300	[4] 165,000

[1] 1968–1969 prices (Significant increases in costs have been experienced recently in some areas).
[2] Line near urban center.
[3] Desert construction.
[4] Includes line sections built over 4-year span.

RESISTANCE LOSSES PER 100 CIRCUIT MILES OF TRANSMISSION

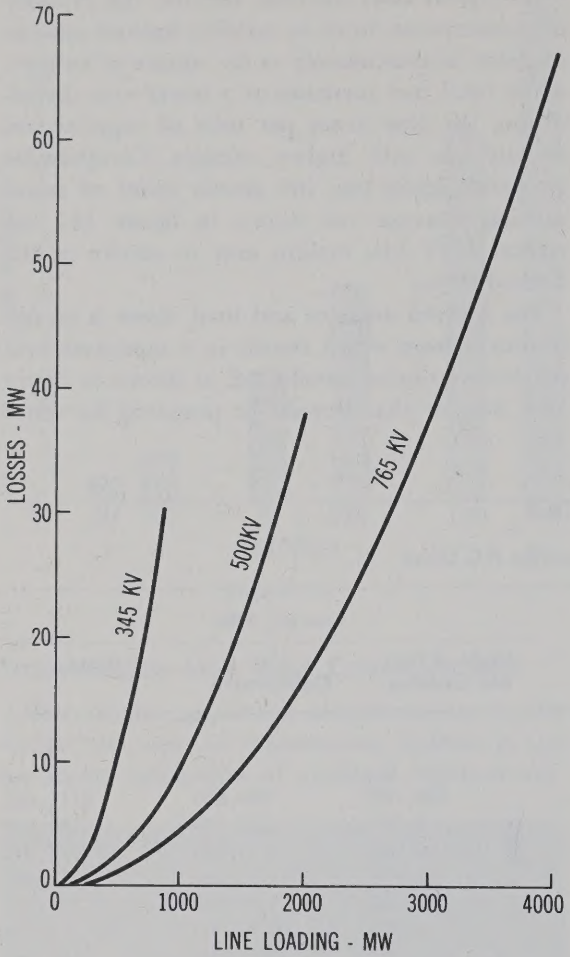

Figure 13.7

conditions, but figure 13.8 is based on the following assumptions:

1. Load factor of 70 percent.
2. Annual fixed charges are 12.5 percent for transmission lines and 13.5 percent for substation facilities. Annual operation and maintenance costs are 1 percent of the investment cost in each case.
3. Installed costs for substations include autotransformers, circuit breakers, and air-break switches, plus property cost of $26,400 and site-development costs. Site-development costs are those suggested in Part II of the 1964 National Power Survey, indexed upward to reflect subsequent cost escalations.
4. Series compensation in discrete amounts of 20, 40, or 60 percent was used where required and, in such cases, the installed costs of capacitors, protective equipment, and switchgear are included.
5. The cost of line right-of-way is $775 per acre.
6. Capacity cost of losses, cost of transmission construction, and various installed costs of equipment items are those appearing in the Commission's 1968 Report, Hydroelectric Power Evaluation (FPC P-35), and its 1969 Supplement (FPC P-38).

There are wide variations in the designs of EHV lines even for the same nominal voltage level. Also, line loadings are often limited by transient stability considerations which depend on the particular system. Therefore, figure 13.8 is intended only to illustrate general relationships and should not be used for cost estimating purposes.

AC Terminal Equipment

Major items of terminal equipment for ac systems include the switchgear, transformers, lightning arresters, and devices for relaying, metering, control, and communications. Transmission substations include insulators, conductors, disconnects, and physical supporting structures to organize and connect individual equipment items into a working assembly, and some stations include equipment for line compensation and power factor correction.

Switchgear

The progression to higher transmission voltages consistently introduces new problems of switchgear design, primarily because of the difficulty in handling switching surge voltages with present insulation techniques. The next step above 765 kilovolts may pose severe problems unless practical ways can be found to reduce the ratio of switching surges to operating voltages. Proposed methods include the insertion of multistage resistors in the circuit during the operating sequence of the breaker, synchronous control of contact operation to assure closure at a point in the cycle which will generate minimum voltage surges, single pole rather than three-phase fault clearing and reclosing, and use of suitable de-

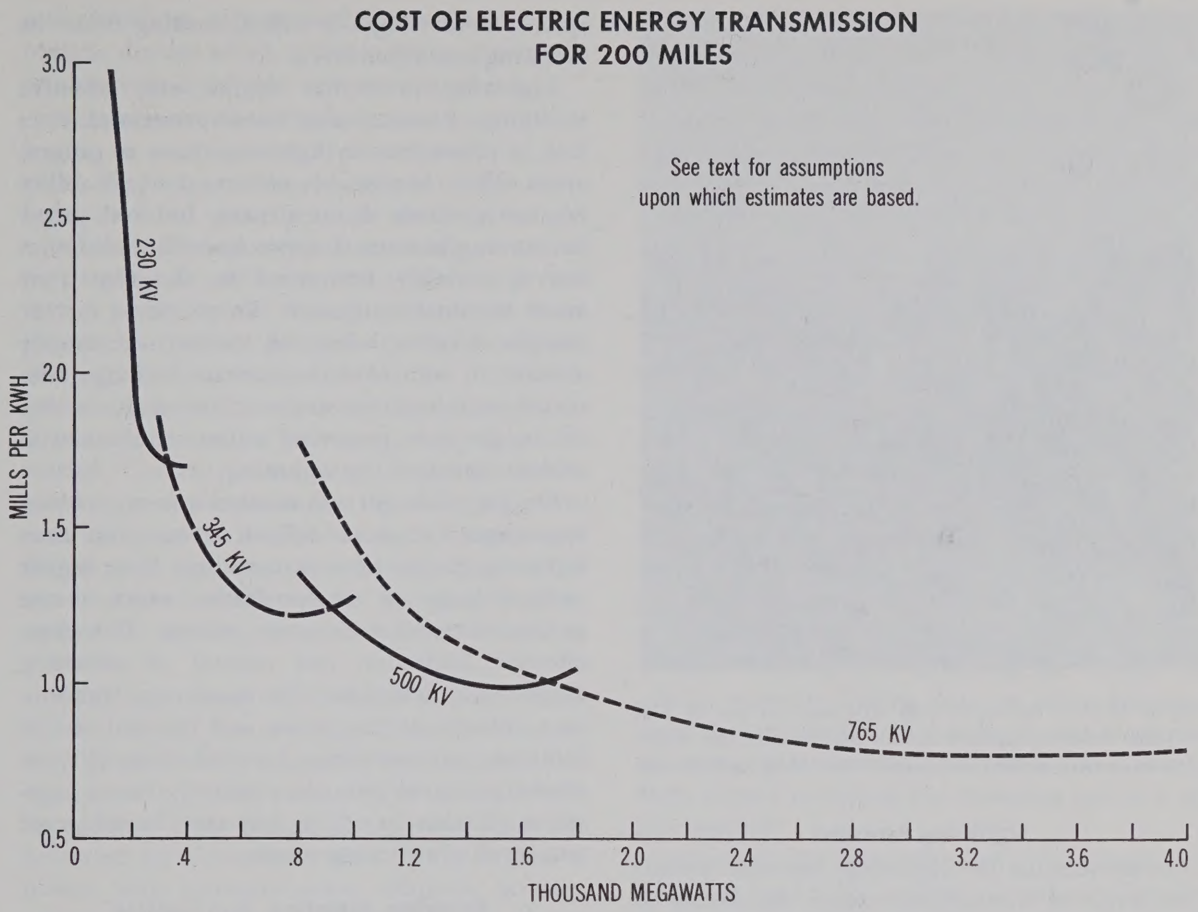

Figure 13.8

vices for draining the trapped charges from the line.

Most of the EHV circuit breakers currently in use utilize either air or sulfur hexafluoride (SF_6) as the primary arc-control medium. Operating times are very short, about $\frac{1}{30}$ of a second of circuit breaker operating time plus not less than $\frac{1}{120}$ of a second of relay time. There is a continual effort to reduce these times, and further reduction will be even more urgent for UHV systems, unless some better way is found to minimize the shock and damage to the system from maximum fault conditions.

Other types of high voltage switches used to isolate energized equipment also require some means of surge suppression to limit voltage spikes during operation.

Transformers

Three-phase transformers now in use on 345-kilovolt systems are approaching capacities of 1,000 megavolt amperes, and banks of single-phase units having three-phase ratings as high as 1,200 megavolt amperes are in service on 500-kilovolt systems. Some single-phase units with ratings up to 600 megavolt amperes are being used on 735-kilovolt systems in Canada. The largest transformers being used on the 765-kilovolt system in the United States are 500 megavolt ampere single-phase units. These reach the maximum size that can be handled under current shipping limits. Improvements in transformer insulation systems during the last few years have increased maximum allowable operating temperatures, permitting higher capacities to be attained without a corresponding increase in physical size. Supercooling may also offer possibilities for reducing the physical size of transformers. Nevertheless, the need for continued increases in transformer capacity may require new approaches to design, and new manufacturing, shipping, and assembling techniques.

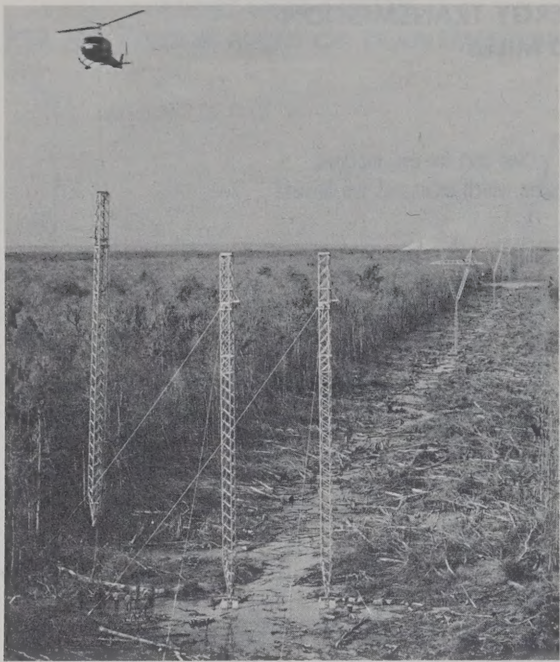

Figure 13.9—A helicopter lifts structures to site of Alabama Power Company's 230-kV transmission line under construction across swampland near Mobile, Alabama.

Lightning Arresters

Improvements in lightning arresters permit the levels of transmission system insulation to be reduced below those of a few years ago, but the inability of arresters to withstand power frequency overvoltages is still a limiting factor in reducing insulation levels.

Lightning protection begins with effective shielding of transmission lines by overhead wires and of substations by lightning masts or ground wires. This considerably reduces the probability of damage from direct strokes. Induced surges originating at some distance from the substation are appreciably attenuated by the time they reach terminal equipment. To provide a further margin of safety, substation arresters are usually selected to withstand the current discharge associated with a direct stroke of unusual severity. Thus, properly protected station equipment is seldom damaged by lightning.

On high-voltage transmission systems, switching surges are more difficult to suppress than lightning surges because they may have higher peak voltages or characteristics which create greater thermal endurance stresses. Therefore, effective limitation and control of switching surges may determine the maximum transmission voltages of the future and the real test of lightning arresters may be their capability to discharge successfully the relatively heavy capacitive currents to which they may be subjected as a result of switching surges.

Relaying, Metering, and Control

The monitoring, control and protection facilities on a transmission system are as essential to reliable electric service as the actual power-handling components. Extensive monitoring of sys-

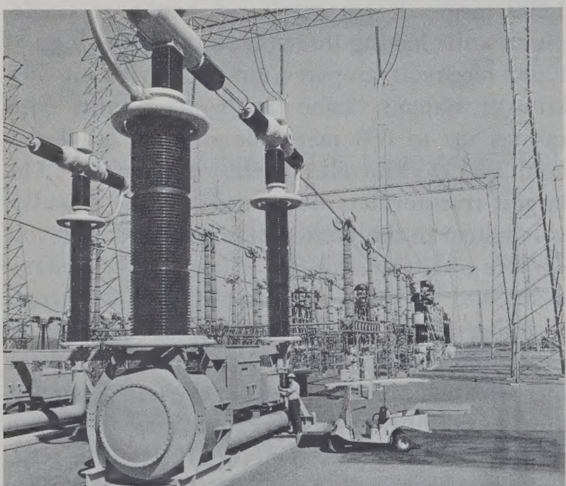

Figure 13.10—High-speed air-blast circuit breakers at one of Pacific Gas and Electric Company's 500 kV transmission substations.

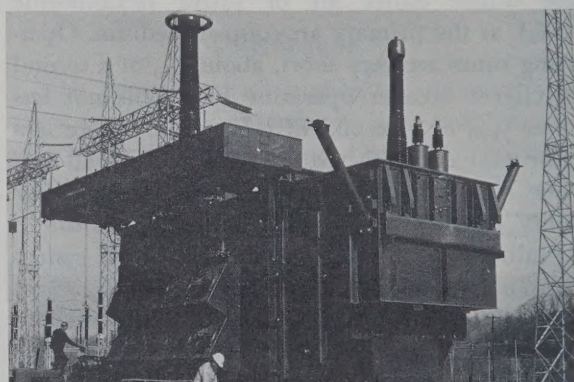

Figure 13.11—Single phase 765/345 kV, 500 MVA, forced oil, air-cooled transformer of American Electric Power Company.

tem conditions is performed continuously by automatic devices which initiate actions directly in some cases and alert the operators in others.

Measurement of voltages, currents, and phase angles, or combinations of these quantities, and rates of change of the measured values have been used for many years to detect abnormal conditions. The quantities are usually measured by coupling the metering and protective devices to the power system through instrument transformers that reduce the primary circuit voltages and currents to values suitable for the instruments. In the modern control systems more accurate devices with faster response times are needed. Current transducers are being investigated as a replacement for the older type current transformers, and pulsed light beams, modulated radio signals, and polarized light sources are in experimental use for coupling intelligence data to the associated meters, relays, or controls.

Relaying systems which detect abnormal conditions initiate the necessary circuit breaker actions to minimize damages by isolating defective equipment or, when necessary, areas of disturbance. Most high-voltage transmission lines are protected by high-speed relays which, in combination with communication channels between terminals, can initiate tripping of the circuit breakers on a faulted line in about $1/120$ of a second. Many protective systems use electro-mechanical relays and occasionally vacuum tube devices, but over the last ten years a number of different types of solid state electronic relays have been installed. Although the latter are somewhat more expensive than their electro-mechanical counterparts, the extra initial cost was expected to be offset by improved operation and lower maintenance requirements. Inadequate performance retarded the acceptance of some of the solid-state devices, but it is reported that problems encountered with early models may have been largely overcome.

Because of the demands for extreme reliability, many utilities are now installing double sets of primary relaying, each independent—or virtually so—from the other. Heavy emphasis is being placed on system protection in the event of breaker failures. EHV systems require better shielding and grounding for control cables and wiring regardless of the types of relays that are employed. It is likely that still greater attention will be required in these areas as even higher transmission voltage levels accentuate problems of electrostatic and inductive coupling.

Recent years have seen the introduction of several new types of high speed recorders for system surveillance and performance analyses. They are valuable for identifying both normal and improper performance during system disturbances and for providing information to enable improvement in system planning and design. Some devices have sufficient memory storage to accumulate information on over 500 events and to subsequently produce a log in proper sequence with two-thousandths of a second time discrimination.

For revenue metering and other important energy transaction records, there has been increasing use of meters which produce punched paper or magnetic tape recordings that can be machine processed to eliminate the necessity of visually scanning and analyzing the records to obtain necessary billing data or other information. A continuation of that trend and more use of central processors with transmission channels from remote sampling and metering points is to be expected.

Several of the newer dispatch and control centers have used large cathode ray tubes as display devices for key elements of system information, and some have employed color tubes effectively to call attention to changes in system conditions. These installations utilize relatively large digital computers to supervise the automatic monitoring routines; accept updated information; compare the new and old readings; and initiate appropriate signaling, display, or other action in response to the detected change of conditions. The same computers are often used for operational analyses and examination of conditions to be expected under planned system changes or emergency conditions. Such installations are now used by some large pools and their expanded use, together with increases in the application of satellite systems reporting to master control centers, is expected to be the trend for the future.

Transmission System Overvoltages

Transmission system overvoltages, sometimes high enough to constitute serious problems, can be experienced under normal conditions because

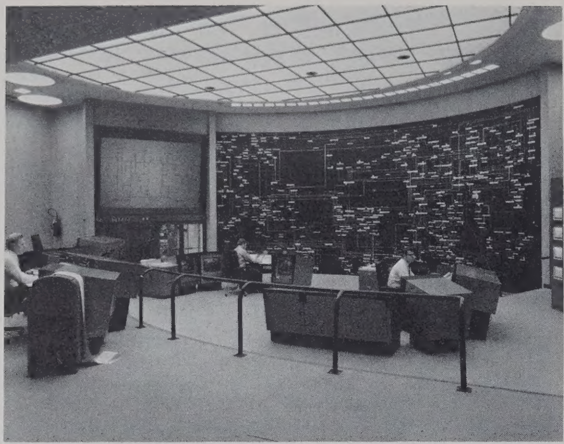

Figure 13.12—The control room of the Pennsylvania-New Jersey-Maryland Interconnection Control Center provides an automated system diagram of the interconnection (rear), a large screen display to show selected substation equipment (left), digital televisions to display messages and diagrams concerning system conditions (center), and strip chart recorders to display pertinent electric quantities (left foreground).

of line charging currents. Shunt reactors can be used to alleviate the condition, although no attempt is made to achieve perfect compensation. System overvoltages often involve complex technical problems and are discussed extensively in Part IV which includes the Transmission Technical Advisory Committee's Report.

Specially designed non-linear reactors for more effective and economical control of overvoltages have been employed on some EHV systems. Further innovations in design, such as variable reluctance core control, may offer a means of future improvement. Minimizing losses and reducing noise levels are other important considerations in the design of reactors, transformers, and other apparatus for high voltage systems.

In the study of overvoltage performance of EHV systems, physical limitations in model simulations and measuring techniques have prevented a full, in-depth analysis of some of the important phenomena involved. Basic assumptions concerning the symmetry of three-phase lines, the modeling of iron-cored (non-linear) elements such as reactors and transformers, and the manner in which sources and loads are represented need to be examined further so that more realistic representations can be incorporated in the models for study of EHV systems and future UHV systems.

Transmission Line Outages

A Joint Committee on Line Outages, formed by the Institute of Electrical and Electronics Engineers and the Edison Electric Institute, reported in 1966 [2] the results of a survey of operating experience with transmission lines in the 230, 287, and 345-kilovolt classes during the period 1950–64. Data covered 386 transmission circuits totaling 25,499 circuit miles, and represented 171,066 mile-years of operating experience. Selected data from the survey are presented in table 13.3. The incidents were grouped in four general categories as follows:

Natural Phenomena—Icing, snow, sleet, lightning, wind, tornado, hurricane, vibrating conductors, insulator contamination, flood, and fire.

Equipment Failures—Line conductor, cable, ground wire, insulator, control device, generator, transformer, other generating station or substation equipment, etc.

System Operation—Overload, overvoltage, undervoltage, switching surge, instability, and misoperation of relays.

Human Act, Foreign Objects, and Unknown—Aircraft impact, vehicular accident, tree damage, animal and bird actions, personnel error, vandalism (including gunshot), sabotage, and unknown causes.

When the 1966 survey was made, the available information on operating experience for 500 kilovolt and higher voltage circuits was considered to be inadequate for reliable indication of performance, so these voltage levels were omitted from table 13.3.

System Stability

The continually increasing size of generating units, the upward trend in transmission voltages, and the growing number of high-voltage interconnections will all have a profound effect on the equipment and operating procedures required to maintain stability of future systems. Changes in steam-supply systems and turbine designs, and improvements in the sensing and response characteristics of control systems will also have an effect.

[2] Extra-High-Voltage Line Outages, IEEE–EEI Committee Report, Paper 31TP66–417, IEEE Transactions on Power Apparatus and Systems, May 1967.

TABLE 13.3

Transmission Line Outages, 1950–1964

	Number of Outages		
	230 kV	287 kV	345 kV
Primary Causes			
Natural Phenomena	996	196	510
System Operation	236	3	52
Line or Equipment Failure	98	4	19
Human Acts, Foreign Objects, and Unknown	329	10	115
	1,659	213	696
Types of Faults			
Line-to-ground	857	44	483
Line-to-line	95	....	48
Line-to-line-to-ground	54	42	20
Line-to-line-to-line	15	....	10
Line-to-line-to-line-to-ground	21	1	14
None	252	26	103
Unknown	365	100	18
	1,659	213	696
Outages Per 100 Miles Per Year			
Natural Phenomena	0.680	1.834	3.459
System Operation	0.162	0.028	0.353
Line or Equipment Failure	0.068	0.037	0.129
Human Acts, Foreign Objects, and Unknown	0.226	0.093	0.780
	1.136	1.992	4.721
Permanent vs Temporary Outages		*Percent*	
Percent of total outages classified as "permanent" (i.e. line was not restored to service automatically in a very short time)	31.9	23.5	18.2

Some of the possible means of improving system stability include:

1. Additional transmission
2. Increased use of line compensation
3. Faster clearing of disturbance by higher speed relays and circuit breakers. (Some power engineers suggest that with present fault clearing time capabilities of about $1/20$ of a second, today's equipment may represent the optimum and the problems associated with larger units, lower inertias, and lower shortcircuit ratios may have to be offset by other means.)
4. Single pole switching.
5. More rapid means of balancing turbine-generator energy input-output through faster operation of turbine valves and dynamic braking. (In some system configurations, the use of high-speed response generator excitation has been found to significantly improve dynamic stability.)
6. Improved monitoring of system conditions, with more comprehensive and faster analysis to detect system abnormalities and determine optimum corrective action.
7. Better and more complete instrumentation in conjunction with computer monitoring systems and more extensive and higher speed communication facilities.
8. More exact methods of simulating system conditions and analyzing stability problems.

Research is under way on these and other related items which bear upon improved system performance and reliability.

High-Voltage DC Transmission

High-voltage direct-current transmission has not been used extensively up to this time, although worldwide there are a number of applications including one in the western United States which had the highest capacity of any dc line in service in 1970. Table 13.4 lists the major installations to date.

The cost of a dc line, excluding terminal equipment, is about 65 percent of an equivalent overhead ac line because of reductions in rights-of-way and materials required for conductors, and lighter supporting structures. This may be noted by comparing figures 13.3 and 13.13 which show ac and dc structures for lines of relatively similar capacity. Dc terminal facilities are expensive, however, so overhead dc transmission usually is economically attractive only for relatively long lines. The unique advantages of no charging current and freedom from frequency variations may make underground dc transmission attractive even for short distances. Some recent studies comparing high-voltage dc to 345-kilovolts ac cable have indicated a breakeven distance of about 30 miles for underground lines in a heavily developed metropolitan area.

A high voltage dc interconnection between the ac transmission systems of Quebec and New Brunswick is under construction. No transmission line is involved; the purpose of the tie is to permit controlled energy interchange between the two systems without requiring synchronous operation. Research investigations also indicate that the use of parallel ac and dc circuits could assist in frequency and tie line control and thus improve stability of transmission networks. Direct current transmission, however, can only supplement and not replace ac transmission systems.

The absence of skin effect and reactive current in dc circuits allows more efficient use of the conductor material than is possible in ac circuits. Furthermore, by utilizing a bipolar arrangement with a suitable ground electrode or an insulated neutral conductor, a single dc circuit can operate at half capacity with one conductor out of service. The emergency monopolar operation of a bipolar circuit with ground return results, however, in a large flow of earth return current, and careful design is needed to prevent possible undesired side effects.

The extent of effects of ground currents on buried metallic substructures, such as pipelines, is dependent upon the relative location of the ground electrodes with respect to the substructures and the configuration and resistivity of the geological formations of the area. The potential for corrosion damage can be minimized by:

1. Careful design and placement of the ground electrodes.

TABLE 13.4

High-Voltage Direct Current Power Transmission Projects

Date of Commission	Line	Voltage to Ground kV	Length of Route (Miles) Cable	Overhead	Total	Approximate Capability MW
	Projects in Operation					
1954	Gotland-Swedish Mainland	100	61	....	61	20
1961	English Channel	+100	34	....	34	160
1963	U.S.S.R. (Volgagrad-Donbas)	±400	....	295	295	250
1965	Konti-Skan (Sweden-Denmark)	250	46	56	102	250
1965	New Zealand	±250	25	360	385	600
1965	Japan (Frequency Changer)	±125	....	....	0	300
1967	Vancouver Island (Canada)	130	17.5	25.5	43	78
1967	Sardinia-Italy	200	73.5	185	258.5	200
1970	NW–SW Pacific Intertie	±400	....	851	851	1440
	Projects under Construction					
1971	Nelson River-Winnipeg	±450	....	600	600	1620
1971	Kingsnorth-London	±266	51	....	51	640

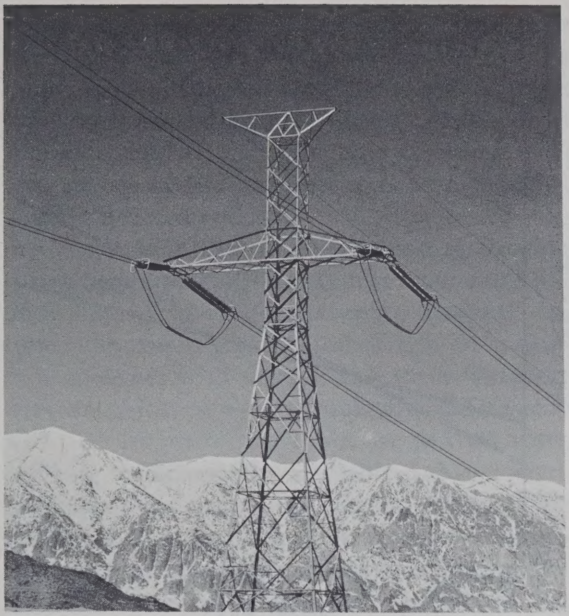

Figure 13.13—Los Angeles Department of Water and Power's towers on 400 kV dc transmission, showing relatively light construction and limited spacing as compared to ac construction.

2. Limiting the duration of any emergency monopolar operation of the system.
3. Modification of existing cathodic protection installations which protect against other sources of corrosion damage.
4. Installation of automatically controlled cathodic protection devices which will respond to changes in ground currents.
5. Installation of an insulated metallic return conductor for use during monopolar operation of a bipolar HVdc system.

Alternating current transmission inherently provides a means of transferring synchronizing power from one area to another, but this is not done automatically in a dc system. To accomplish the equivalent results with dc will require development of extremely fast sensing and control devices. The asynchronous nature of a dc line can be an advantage in some cases, however, in that it does not transfer the ac transients between systems in case of a disturbance.

Strong harmonics generated by the converter valves are a disadvantage of dc systems. Most of these harmonics can be filtered out, but the cost for the filtering equipment may be as much as 15 percent of the cost of the converter station. The filter capacitors do, however, contribute some part of the needed system reactive supply and part of the cost can, therefore, be allocated to that use.

EHV converter stations built in 1970 or earlier utilized mercury-arc valves to convert the ac to dc, (or vice-versa). Solid-state devices, which are cheaper and smaller, are now available and are expected to become the dominant type for future use. In both instances, the valve groups have voltage ratings which are usually lower than the desired dc system voltage level. Consequently, groups of valves are connected in series to provide the desired voltage rating for the high-voltage dc system. Single mercury-arc valve groups have a maximum rating of about 135-kilovolts, while solid-state rectifier modules have been constructed for voltages of only 20-kilovolts.

A new lightning arrester, designed especially for EHV dc applications has been developed recently in the United States, and is used on the Pacific Northwest-Southwest dc tie. The new arresters provide superior protection to that afforded by the conventional ac arresters used on dc systems in the past.

Some limitations currently contribute to the inflexibility of dc transmission. For example, no high-voltage dc circuit breakers are commercially available, so short circuits must be interrupted by changing the terminal rectifier mode to inverter mode so that the fault current is blocked and the line discharged. If efforts being devoted to developing a suitable dc circuit breaker are successful, converter fault control could be eliminated, and tapping of dc lines between terminals would be possible, thus enhancing the value of dc transmission for general use.

The cost of each Pacific dc intertie terminal was reported to be in excess of $40 per kilowatt. Even if there should be a significant downward trend, dc switching station costs for some time will be considerably more than the $6 to $8 per kilowatt for an ac station of comparable capacity.

About 21 acres of land were required for one of the 1440 megawatt dc terminals completed in 1970 (figure 13.14). This includes space for a service building, valve hall, converter-transformer, valve damping facilities, ac filters and power factor equipment, dc filters and miscellaneous equipment, Faraday shields to prevent ra-

diation of high-frequency harmonics, ac and dc structures, buses, oil-handling equipment, outdoor valve degassing equipment, entrance and service roads and employee parking areas. An ac station of comparable capacity might require about 15 acres.

Some of the economic considerations in dc transmission, compared to ac, may be summarized as follows:

1. Construction of the transmission line, overhead or underground, is less expensive.
2. For comparably rated lines, transmission losses are less.
3. Transmission cable capacities are not limited by reactive charging currents.
4. Modern dc lines do not add appreciably to the short-circuit capacity requirements of their receiving buses.
5. The asynchronous nature of dc lines may be an asset in some situations.
6. Transmission terminal stations are appreciably more complex and expensive than their ac counterparts, both for initial cost and operating and maintenance expenses.

Comparative costs in mills per kilowatt-hour for comparable-capacity dc and ac circuits, for a range of mileages for which the shown voltage levels might be considered, are illustrated graphically on figure 13.15.

The inherent attractive characteristics of dc and the availability of improved equipment should encourage the use of dc as a means of transporting large blocks of energy into con-

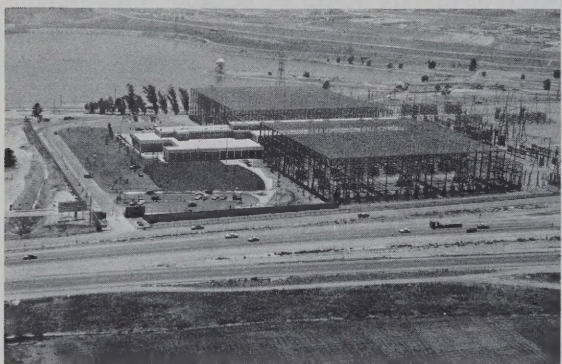

Figure 13.14—Sylmar ±400-kV ac-dc converter station near Los Angeles. This station suffered extensive damage during the severe earthquake in the Los Angeles area on February 9, 1971.

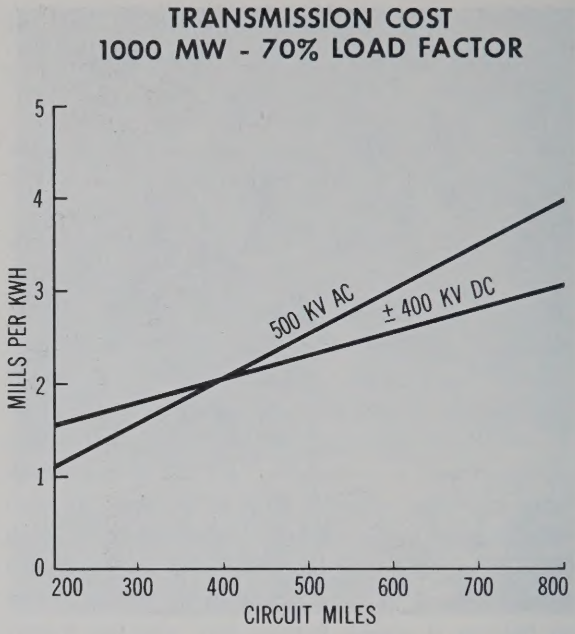

Figure 13.15

gested areas, particularly where underground installations are dictated. The combination of direct current transmission and some of the cryogenic cable systems being studied appears attractive for future use when 5,000 to 10,000 megawatts of capacity must be moved into large load centers.

Underground Transmission

In April 1966, the Federal Power Commission's Advisory Committee on Underground Transmission issued a report on underground technology and practices, and the estimated cost of underground versus overhead systems. There have been few changes since the 1966 report, but extensive research currently underway may provide solutions to some of the major underground transmission problems.

The highest voltage ac underground transmission cable currently in service is 345-kilovolts, and the most extensive system is that of the Consolidated Edison Company in the New York City area. A higher voltage installation, utilizing 525-kilovolt oil type cables, will connect the new power plant and 500-kilovolt switchyard being constructed at Grand Coulee Dam. Paper will be used as the insulating medium, and the cable system will operate at a pressure of 265 pounds per square inch. The first section of the

system is to be installed by July 1, 1973. The complete installation will involve three circuits (nine cables) with an average length of about 6,500 feet. Each cable will utilize a 2,000 kcmil copper conductor and will have a normal current rating of 711 amperes (about 650 MVA, 3-phase, at rated voltage).

A major difficulty of underground alternating current transmission lines results from a continuous flow of so-called "charging current" between the conductor and the sheath. Its magnitude increases with voltage and varies inversely with the thickness of the insulation and directly with the length of the cable. At 345,000 volts, utilizing commercially available cable, practically all of the current-carrying capability of the uncompensated underground conductor is utilized by this charging current in a distance of about 26 miles. Therefore, no capability is left for useful current to be transmitted, unless very expensive and bulky compensation equipment is installed.

Another consideration prohibiting extensive undergrounding of transmission systems is insulation. Overhead lines are insulated by the air surrounding the conductors and by the long strings of supporting insulators. Underground lines require very high quality insulation around each conductor, with the insulated conductors enclosed in a conduit, generally an oil-filled pipe. Although great advances have been made in insulation, the cost is still high because of the exacting work required. The most common method used to provide insulation for underground transmission lines is to wrap each conductor with an oil impregnated insulating material.

Problems are also encountered in connections between underground lines and substations. Abrupt insulation changes cause very large concentrated electrical stresses, which can only be eliminated, using currently known techniques, by terminating the cable above ground in an expensive device known as a "pothead." The internal construction of a pothead is very complex, both mechanically and electrically.

Underground lines have the further disadvantage of poor accessibility. According to the Advisory Committee on Underground Transmission in its 1966 report to the Federal Power Commission, overhead lines have more outages than underground per unit of length but the outages are usually shorter in duration. Because of the longer repair time for underground systems, expensive duplicate facilities are sometimes installed to reduce the risk of overlapping outages. Overhead lines have greater flexibility because connections and repairs are relatively simple and they can be converted to higher voltage if necessary. Underground systems cannot easily be altered.

On the basis of present technology, it is estimated that in suburban areas underground lines cost on the average about 8–½ times as much as overhead lines at 138,000 volts, and about 15 times as much at 345,000 volts. Because of lower rights-of-way costs in rural areas, the comparable figures are 10 and 19 times as much, respectively, for average conditions. The economic costs would be higher if existing overhead lines are prematurely converted to underground because the undepreciated values of the discarded facilities must be considered in the analyses. As transmission costs represent between 10 and 20 percent of the costs paid by consumers for electricity, the significance of these increases in the cost of transmission can be readily understood.

There are fewer technical problems in undergrounding direct current transmission lines than are encountered in alternating current systems. For example, the charging-current problem does not exist with direct current. However, the conversion problems discussed previously apply to underground as well as overhead direct current transmission.

Research efforts and suggested needs for the future are discussed in more detail in chapter 21.

Power System Communications

The increased complexities of power systems and extensive coordination of area and regional networks have expanded the needs for the reliable communications necessary for monitoring, supervision, and control. Records indicate that the annual investment in power system communication facilities increased at a rate of about 10 percent for the years before about 1952, and about 15 percent for the years since. A growth rate similar to that for the latter period is expected for at least the next 15 to 20 years.

Power system communications involve a wide variety of functions and many different types of

Figure 13.16—Splicing a 345-kV underground cable. This critical operation requires careful control of dust, temperature, humidity and other conditions in the manhole and other work areas, and takes nearly 200 hours for two splicers and their helpers. There are approximately 300 splices in the 90 circuit miles of 345-kV cable now in operation on the Consolidated Edison Company's system.

equipment. In addition to the voice communication requirements, most systems now utilize communication channels to transmit system information to central control points; to connect supervisory control terminals to their associated remote stations; to operate teletype and related information transfer facilities; and to facilitate rapid signaling for high-speed protective relay applications. Many larger utilities utilize sophisticated communication systems in the high-speed transfer of data for computer systems that perform functions varying from periodic monitoring and the annunciation of unusual conditions to automatic control of some operational functions. There has been an increasing trend in the use of digital equipment for both data transmission and computation, and a number of utilities are now using digital telemetering channels to transmit information.

Utilities use virtually all of the common communication media, such as wire lines, cables, radio, microwave, and carrier-current circuits. Carrier-current equipment is usually coupled to the power line conductors, and operates in the 30–200 kilohertz range. In recent years, a number of companies have insulated the ground wires on high-voltage lines to make them usable for communications circuits. The ground wires are insulated for flashover at voltages well below nominal line voltage so that they can protect the primary line conductors against lightning discharges. Most utilities also make extensive use of mobile radio for communication between control centers and operations and maintenance personnel.

A sizeable increase is anticipated in intersystem communication links, both for exchange of information and for the control and operation of interconnected systems. Improved reliability through status monitoring and evaluation, real-time or on-line simulation, and control methods will require accompanying improvements in communication facilities.

Research and Development Needs

Satisfactory solutions to the technical problems involved in raising ac transmission voltages above the 765-kilovolt level now in use for overhead circuits, for 345-kilovolt ac now used for underground transmission, and for expanded use of high voltage dc transmission will require additional research and development effort, if the industry is to meet the demands of the public for both more electric power and a better environment. A discussion of research and development needs related to transmission of electric power appears in chapter 21.

Figure 13.17—The Roosevelt Mountain Microwave Repeater Station, part of TVA's intrasystem power communications network.

CHAPTER 14

DISTRIBUTION SYSTEMS

Introduction

Electric power distribution facilities are designed to subdivide bulk power and deliver it at suitable voltages to the individual users. They include step-down transformers which reduce transmission voltages, low voltage primary and secondary distribution lines or feeders, customer service transformers, and connecting services to the customers' premises. The distribution systems account for nearly 40 percent of the total investment in electric power facilities.

In this chapter, attention is given to the problems and costs of power distribution to the year 1990, including the cost impact of increasing use of URD (Underground Residential Distribution) in new subdivisions, and of placing underground other new distribution circuit extensions. A more extensive discussion of distribution systems is included in a report to the Federal Power Commission on The Distribution of Electric Power prepared by The Distribution Technical Advisory Committee for the National Power Survey. The Committee's comprehensive report is printed in Part IV of the National Power Survey.

General Considerations

Most of the physical distribution facilities, representing a nationwide investment of about $40 billion in 1970, are to provide electric service to the smaller individual users of electric energy, namely residential and commercial customers. These two classes of customers accounted for about 99 percent of utility customers in 1970, but only about 50 percent of the electric energy sold to ultimate consumers. Many of the industrial and other large-use customers receive their power at transmission voltage or through single-customer substations connected directly to the transmission or subtransmission system.

Average customer cost per kilowatt-hour of electricity used is highest for residential service and lowest for the large users, principally industrial. Any major increase in the cost of distribution facilities serving the residential customer, such as that associated with vastly increased use of underground facilities, could enlarge this spread.

Distribution System Loads

Growth in number of electric customers and in average use per customer are the principal factors affecting the requirements for new facilities and additional investments necessary to meet future service needs. The total number of customers is expected to increase about 50 percent by 1990 and use per customer is expected to increase substantially for each class of service. As noted in chapter 3, average industrial use is expected to experience nearly a 5.5 fold increase from 1965 to 1990, residential use is expected to increase from 4,700 kilowatt hours per household in 1965 to 15,900 kilowatt hours in 1990, and the number of households is expected to increase from 57.3 million to 92.2 million. Most new residential customers are expected to install more major appliances initially, and to use more energy than the average for all residential customers. This expectation is confirmed by the data in table 14.1, based on a canvass of utilities by the Distribution Technical Advisory Committee.

Data relating to energy use are helpful, but of more interest to distribution engineers is the rate of use (kilowatt demand), as it is the major factor in determining the required capacity of facilities. Another factor called load density, usually expressed in kilowatts per square mile, is an important parameter used in determining the type and capacity of distribution facilities needed for serving a particular area.

TABLE 14.1

Energy Sales Per New Residential Customer, Single-Family and Multi-Family Dwellings

Class of Customer	Annual kWh Per New Customer			
	1965 (Act.)	1970	1980	1990
Single-Family Residential				
Small-Use	3,900	5,000	7,200	10,200
Medium-Use	7,000	8,900	13,200	19,000
Large-Use	16,500	19,900	26,600	35,300
Multi-Family Residential				
Small-Use	3,000	3,700	5,100	7,100
Medium-Use	5,000	6,000	8,100	11,600
Large-Use	9,700	11,800	15,400	20,400

Load Densities

Load density is the product of customer density and coincident peak load per customer. Customer density is increasing rapidly because residential customers are showing an increased preference for apartment living. The peak load per customer is also increasing even though an individual customer may use more electricity in a single-family dwelling than in a multi-family unit. Another influencing factor is the rapid increase in use of mobile homes, many of which are all-electric and large-use customers. The net result is considerably higher load densities in urban and suburban areas, which will have an influence on the design, economics, and performance of future distribution systems.

Residential customer densities in areas of single-family dwellings vary generally from one to eight homes per acre. With low rise multi-family buildings, there may be 20 or more family dwelling units per acre, and with high-rise apartment buildings, 100 or more.

In the business centers of cities, load densities are usually much higher than in predominantly residential areas. Densities vary with the sizes of business centers, heights and types of the buildings, and other factors. In major metropolitan centers, densities of 100,000 to 300,000 kilowatts per square mile were typical in 1970, and densities of 350,000 to 1,000,000 kilowatts per square mile are projected for 1990.

The forecast of 1990 distribution system loads envisions nearly four times the 1970 energy use and suggests the magnitude of the task ahead for the industry. A very large increase in distribution system investment will be required. Higher distribution voltages will be used, and new distribution design concepts will have to be developed. New types of equipment, as yet undeveloped, will be required if low-cost electric service is to be continued.

Design of Facilities

Distribution design practices are presently undergoing changes to meet changing criteria related to environmental considerations. Many existing overhead distribution lines create a vista of unsightly poles with multiple crossarms, numerous wires, and conspicuous appurtenances such as large transformers. When those lines were constructed, the criteria for design were primarily performance and minimum cost. Today, appearance is an important criterion in the design of overhead lines. Striking improvements have been attained through the use of new designs, materials, and concepts; however, most of these changes increase the costs. The methods being used to improve environmental conditions are discussed in chapter 12.

Quality of Service

Performance of distribution systems and quality of the service provided usually are measured in terms of freedom from interruptions and maintenance of satisfactory voltage levels at the customer's premises.

Reliability

It is technically possible today to achieve almost any specified degree of distribution service reliability. However, economic factors usually

dictate the adoption of a service level that satisfactorily meets customer needs.

The requirements for service reliability vary with the nature of the load and the area being served. A very high degree of reliability is essential for metropolitan downtown areas where a service interruption adversely affects large groups of individuals and businesses, and where continuous operation of elevators and other public facilities is essential. Fortunately, the load density of such areas is sufficiently high to make it economically feasible to provide a very high degree of service reliability. A corresponding level of reliability may not be economically justifiable for customers in a low density residential or rural area because the hazards of service interruptions are not significant enough to justify the higher costs of near perfect service.

Reliability of service to a particular area can be increased by various design and construction practices such as supply from more than one primary circuit, automatic transfer between sources, spot networks, and secondary network systems. Other measures to improve reliability include adequate maintenance and operating practices, such as selective tree trimming, up-to-date overcurrent protection schemes, minimum line exposure per customer, and conscientious efforts to report trouble, damage and interruptions.

Most distribution system service interruptions are the result of damage from natural elements, such as lightning, wind, rain, ice, and animals. Other interruptions are attributable to defective materials, equipment failures, and man-made actions such as vehicles hitting poles, cranes contacting overhead wires, felling of trees, vandalism, and excavation equipment damaging buried facilities. Some of the most damaging and extensive service interruptions on distribution systems result from snow or ice storms that cause breaking of overhanging trees which in turn damage distribution circuits. Hurricanes also do widespread damage, and tornadoes are even more intensively destructive though generally quite localized. In such severe cases, restoration of service is hampered by the conditions causing the damage, and most electric utility systems do not have a sufficient number of crews with mobile and mechanized equipment to rapidly restore all service when a large geographic area is involved.

Figure 14.1—Maintenance of overhead distribution systems is expedited with truck mounted equipment of Public Service Company of New Hampshire.

It is common practice for a utility to draw on other utilities and line construction contractors for assistance in such emergencies. Eighty-three utilities participate in a mutual assistance roster to facilitate placing calls for such assistance. This program was initiated and is currently maintained by the Mutual Assistance Coordination Task Force, an activity of the Edison Electric Institute's Transmission and Distribution Committee. Other utilities have formed regional groups which have arrangements for mutual assistance. Experience shows that such assistance has been readily and effectively given when needed.

Voltage Control

Another element of service quality is the requirement that a distribution system maintain a voltage level at each customer's service entrance that is within limits appropriate for his type of service. Because of economic considerations, electric utilities do not attempt to supply each customer with a constant voltage corresponding exactly to the nameplate voltage on his utilization

equipment. Instead, normal practice is to adhere to preferred voltage levels and ranges of variation for satisfactory operation of equipment, as set forth by the American National Standards Institute, Inc. Regulatory agencies of many states also prescribe voltage limits for various classes of electric service.

Voltage Control Methods

Voltage is controlled on distribution systems in a number of ways. At the substation, the voltage may be regulated by transformers that are equipped with tap changers that operate automatically under load, by regulators and/or capacitors that maintain the desired voltage level on the substation bus, or by separate regulators for each feeder.

Voltage regulating devices are designed to maintain automatically a predetermined level of voltage that would otherwise vary with the load. As the load increases, the regulating devices boost the voltage at the substation to compensate for the increased voltage drop in the distribution feeder. In cases where customers are located at long distances from the substation or where voltage drop along the primary circuit is high, additional regulators or capacitors, located at selected points in the line, provide supplementary regulation.

In addition to regulating voltage, capacitors in substations and on primary circuits serve the further purpose of improving power factors. Many of these installations have sophisticated controls designed to fulfill either or both purposes by automatic switching. In some instances, automatically switched capacitors have replaced conventional step or induction regulators for control of voltage on distribution feeders.

Heat dissipation problems and high cost of switching equipment will limit the use of direct buried capacitors for voltage regulation on underground distribution circuits until such time as the associated economic and technical problems can be overcome. Several test installations have been made with good results, indicating these problems will be resolved.

Methods for Improving Service

It is likely that, in the future, practical means will be available to supply remote reading of each customer's meter, and to record remote operation of distribution line switches over a common communication channel. Experimental installations and future needs related to distribution of electric power are discussed in chapter 21.

Quality of Underground Service

The extensive use of underground distribution anticipated in the immediate future may produce new service reliability problems unless thoroughly tested materials are used. In an effort to keep installation costs as low as practicable and not delay undergrounding of distribution facilities, many new concepts are being utilized that have not been adequately tested. While most of the new concepts and designs should provide facilities that operate satisfactorily, failures may be more numerous than anticipated.

Distribution Economics

Since approximately 40 percent of the industry's investment is in distribution facilities, distribution system costs materially affect what the customers pay for electric energy. The potential impact on costs of possible programs for undergrounding distribution system facilities and distribution system cost data presented herein are for the contiguous United States. No attempt has been made to show costs by regions

Figure 14.2—Installation of overhead distribution systems is expedited with truck mounted equipment by Northeastern Utilities.

or types of ownership. Annual costs are expressed in mills per kilowatt-hour, using as a base the total kilowatt-hours sold to all electric retail customers of the industry. This base includes the energy delivered directly, at transmission voltage or through single-customer substations connected directly to transmission systems, to a relatively small number of large-use customers. The amount of energy sold to such large customers is estimated to be about 25 percent of all the energy sold. Consequently, if only the energy delivered through distribution systems were used as the base, the costs per kilowatt-hour would be about one-third higher than those used for analytical purposes in the following discussion.

Distribution Costs and Cost Trends

The total investment in distribution facilities in 1968 was estimated to be $35.9 billion, or $517 per customer. Annual costs were $6.6 billion, equivalent to 5.5 mills per kilowatt-hour sold.

Historical trends show annual increases in both the distribution system investment per customer and the distribution operation and maintenance expense per customer. However, because kilowatt-hour use increased more rapidly than both the investment and operation and maintenance expenses, the trend of annual distribution costs per kilowatt-hour was downward. This trend is expected to continue to 1990. Therefore, in terms of constant dollars, it is estimated that the annual distribution costs per kilowatt-hour will decrease to 4.5 mills by that year.

Trends of distribution costs are influenced by a number of factors and it is improbable that future costs will follow the trend curves of the past. In order to develop forecasts of probable future costs levels, it is necessary to examine each factor and consider whether its influence upon future costs will be similar to its influence in the past.

Factors Tending to Reduce Costs

Increasing customer densities and larger use of energy per customer permit more energy to be distributed per mile of distribution line, per substation, and per line transformer. The higher capacity components, used to transmit the increased energy, cost less per unit of capacity. During the period 1965 to 1990, the number of households is expected to increase about 60 percent and the electric energy used per household more than 230 percent. These factors will, therefore, tend to decrease unit distribution costs, although the magnitude of this influence probably will not be as great as in the past.

Technological progress will also contribute to the downward trend of unit distribution costs. This should include development of higher capacity components, development and application of reliable lower cost materials, improvement in manpower efficiency through automation, and optimization of system designs.

Primary circuit capacities will continue to be increased by the use of larger conductors, higher power factors, and most importantly, higher primary distribution voltages. In combination with increased load density, this will permit the use of larger, more economical substations, thereby reducing substation costs per kWh. These trends to lower unit costs are expected to continue but they may be approaching a point of diminishing return. On some systems, overhead conductor sizes are now approaching practical limitations and power factors have been raised to near unity. As primary circuit voltages are increased, the unit costs of line transformers and line switching and protective equipment also increase and tend to limit the overall potential savings.

Other cost-reducing factors include better communications which improve utilization of maintenance crews and equipment, greater mechanization of maintenance operations, expanded use of supervisory control and automation, and increased use of computers. These contribute to more efficient use of engineering, construction, maintenance, operation, and clerical manpower, and thereby reduce costs.

Factors Tending to Increase Costs

The principal factors that cause increases in distribution costs are rising prices of materials and labor, increasing standards of service reliability, increasing cost and difficulty of acquiring properly located substation sites, changes necessary to improve the appearance of distribution lines and substations, and added costs of constructing a greater proportion of facilities underground.

The greatest single impact on higher costs will be the rapidly increasing use of under-

ground distribution facilities. The use of such facilities to serve new residential and new commercial developments is fast becoming normal practice.

There are considerable differences in the current ratios of underground to overhead costs quoted by electric utilities for construction of the same types of lines. These reflect differences in local conditions and in undergrounding methods and techniques. Although somewhat speculative, the distribution Technical Advisory Committee estimated the average 1967 ratios of underground to overhead investment costs of new line extensions, and the probable future range of these ratios, are shown in table 14.2.

Because of very limited operating experience with new types of underground lines, it is impossible to make reliable quantitative comparisons of future operation and maintenance expenses between such systems and equivalent overhead systems. Some of the common expenses of operating and maintaining overhead systems are tree trimming, repairing damage and restoring service after vehicle collisions, and damages caused by snow, ice, wind, and lightning storms. These expenses would not normally be incurred with underground distribution systems. However, underground lines have other expenses resulting from entrance of moisture, corrosion, insulation failure, and accidental damage by excavation equipment. On the basis of the limited experience available, operation and maintenance costs of underground systems are expected to be higher than for equivalent overhead systems.

TABLE 14.2

Average Ratios of Underground to Overhead Costs for Extensions

	1967	Probable Range 1980–90 Maximum	Probable Range 1980–90 Minimum
URD Type Lines [1]	1.8	1.5	1.3
Other Types of Lines [2]	5.0	4.0	3.3
All Lines—Weighted Average	2.9	2.7	2.3

[1] URD (Underground Residential Distribution) type lines are branch lines serving new residential subdivisions, predominantly single phase and with relatively small primary conductors.

[2] Other types of lines include distribution in new commercial and industrial developments, and rural areas, and main primary circuits of large conductor through residential as well as other areas.

Figure 14.3—Modern equipment such as this cable plow speeds installation of direct burial underground distribution lines.

In spite of higher costs, undergrounding rather than overhead installations of distribution systems is gaining momentum. Declining underground-to-overhead cost ratios coupled with encouragement, and in many cases requirements, of governmental bodies at all levels will accelerate this trend not only for URD, but also for extensions of commercial, industrial, some rural, and main primary feeder lines.

The Distribution Technical Advisory Committee estimated that about 20 percent of all the extensions built in 1968 were placed underground, and that this percentage would increase to 70 percent by 1975 and 90 percent by 1990. Even though most new distribution line extensions are expected to be underground, the total mileage of overhead distribution lines to 1990 is expected to continue to increase because only limited conversions from overhead to underground are anticipated.

Effect of Undergrounding on Distribution Investment

Between 1968 and 1990, the estimated additional cost required for undergrounding new distribution systems will be in the neighborhood of $29 billion, and nearly $20 billion more is expected to be expended for undergrounding existing overhead lines. The Distribution Commit-

tee's estimates of increases in distribution investment in 1980 and 1990, based upon expected underground extensions and the cost ratios given in table 14.2, are shown in table 14.3.

The effect of underground extensions upon the delivered costs of energy in 1980 and 1990 will depend largely upon the extent to which the electric utilities recover the required added investments either through contributions in aid of construction or by other means. Such contributions reduce the fixed charges on investment because the utility does not need to pay interest on the contributed capital and there are no income taxes associated with it. Thus, the fixed charges on contributed capital are limited to depreciation, replacements, insurance, and other taxes, and average about four percent per year, rather than the overall industry composite of 13.5 percent that applies to utility capital. Irrespective of how new underground distribution is financed, the customer will ultimately pay most of the bill.

The rate of conversions of existing overhead to underground will be influenced, in great measure, by its cost. Estimating average underground to overhead cost ratios for conversions is subject to the same and some additional difficulties and uncertainties as for new line extensions. In general, conversion cost ratios are much higher than for new extensions because of the unfavorable construction conditions in built-up areas. To examine the cost impact of undergrounding, the Distribution Committee projected conversion costs in terms of ratios to the original cost of the lines converted, rather than to the cost to build equivalent new overhead lines. The Committee concluded that assuming an average age of 15 years for the existing overhead distribution lines, with construction costs increasing at about 2.4 percent per year during the 1952–67 period, the original cost of existing overhead lines would be about 70 percent of the cost to build equivalent new lines. Therefore, the ratios based on the original assumed cost are about 40 percent higher than if the ratios were based on the cost of new overhead lines.

The Distribution Committee's estimates of ratios for conversions in 1967 and for the 1980 to 1990 decade are shown in table 14.4. Different future average ratios are indicated for "selective" and for "general" conversion programs. Selective programs would be largely concentrated in commercial and civic areas, whereas general programs would involve an increasing percentage of less costly residential area conversions resulting in lower overall average costs in the future.

Suggestions for complete elimination of overhead distribution lines and facilities are voiced occasionally with apparently little realization of the impact of such a conversion program on costs. The Electric Utility Industry Task Force on Environment estimated that the cost of converting all existing overhead distribution to underground would be in the order of $150 billion. This may be compared with the total investment in distribution facilities of approximately $40 billion in 1970. The Commission's Technical Advisory Committee on Distribution estimated that placing 90 percent of all distribution underground by 1990 would increase the 1970–1990 expenditures for distribution systems by about $175 billion over the cost of an all overhead system. Both the Task Force and the Advisory Committee concluded, therefore, that the conversion of all existing lines to underground would be virtually impossible. Much can

TABLE 14.3

Effect of Increased Undergrounding of Extensions on Investment

	Millions of Dollars			
	1980		1990	
	Maximum	Minimum	Maximum	Minimum
Added Underground Investment	$16,000	$14,500	$52,200	$44,600
Less Overhead Investment Avoided	6,200	6,200	19,300	19,300
Net Increase in Investment	$9,800	$8,300	$32,900	$25,300

Figure 14.4—The installation of underground distribution lines in new suburban developments is now common practice.

be accomplished, however, by selective conversion of existing overhead distribution lines to underground. Both groups recommended that effort be directed toward undergrounding certain lines as soon as possible in areas of recognized priority, generally within urban and suburban areas. A further classification of priorities would be helpful in developing the schedule on which eventual conversion may be expected. Local municipal options and desires will be critical. The Working Committee on Utilities recommended that the conversion of overhead distribution lines be made a national goal and assigned an appropriate level of priority among other national objectives.

Those electric utilities which have not already done so should establish selective conversion programs. One means of assuring the implementation of the programs would be to budget a fixed percentage of annual revenues for this purpose.

Most of the conversions in the limited programs accomplished in recent years have been associated with renewal projects in selected urban and outlying areas, in growing centers of business and shopping where overhead construction is visually obtrusive, and in a few residential areas where property owners have provided the funds for the conversion. It can be expected that future conversion programs will continue to be related to over-all community improvements, urban renewal, or street improvement programs. Many utilities have, in cooperation with municipal or regulatory bodies, developed selective programs of conversion to underground in congested areas.

TABLE 14.4

Average Ratios of New Underground Cost to Original Overhead Cost for Distribution Line Conversions

	1967	1980–90	
		Maximum	Minimum
URD Type Lines.......	7.0	5.6	4.7
Other Types of Lines.....	10.0	8.0	6.7
Weighted Averages			
Selective Programs.....	9.7	7.8	6.5
General Programs.....	9.7	6.8	5.7

In 1968, Arizona passed a law authorizing the establishment of underground conversion service areas upon petition of not less than 60 percent of the property owners in a particular area served by overhead distribution facilities. When undergrounding is accomplished, the costs are apportioned to all property owners within the underground conversion service area. A similar law in California permits districts to be formed in unincorporated areas for the purpose of converting overhead electric lines to underground. A majority of the votes cast determines whether a district shall be formed and a two-thirds affirmative vote is required for the issuance of bonds. Once established and funded, all those in the district are obligated to pay their share of the costs.

In view of the very large costs required to convert overhead distribution to underground, the Electric Utility Industry Task Force on Environment concluded that in order to establish an effective conversion program, Federal financial assistance would be necessary. It considered two types of Federal assistance: tax incentives, and grants-in-aid to cities and other public juris-

dictions. The Task Force favored Federal grants-in-aid. The Working Committee on Utilities expressed the view that tax incentives, grants-in-aid, and regulatory rate-making techniques should be considered as complementary means to encourage conversions.

The Department of Housing and Urban Development has a number of programs that have included or could include grants for undergrounding and conversion of existing overhead facilities to underground, but the amounts of money available for such uses are small.

CHAPTER 15

UTILITY PRACTICES AFFECTING RELIABILITY OF SUPPLY

Introduction

In the Commission's report on the Prevention of Power Failures, issued in July 1967, a number of reliability characteristics of United States power systems were reviewed. The information collected at that time indicated that many utilities had plans for improving system reliability but that few had actually accomplished all of the measures which were deemed desirable. Subsequently, much has been done to improve reliability, as shown by the following summaries and evaluations.

Both the Commission and its Advisory Committee on the Reliability of Electric Bulk Power Supply, which assisted in preparing the 1967 report, recommended the formation of regional and national coordinating councils to promote regional bulk power system reliability and coordinating councils to promote regional bulk power system reliability and adequacy. The regional councils have been formed and are operating under the guidance of the National Electric Reliability Council (NERC).[1] In 1969 NERC's Technical Advisory Committee (TAC) conducted a questionnaire-type survey of the design, operation, and maintenance practices of individual systems and regions that affect bulk power supply reliability. The survey covered a total of 147 major United States utilities, constituting approximately 90 percent of the total generating capacity of the United States and, therefore, reflected the reliability practices which affect most utility customers throughout the Nation.

The information presented in this chapter is taken principally from the NERC-TAC survey, and is based on the reliability practices as of that time. General information on the systems covered in the NERC-TAC survey is shown in table 15.1.

[1] The Councils are listed and their history is discussed in chapter 17.

System Planning and Operation

Contingency Tests

Contingency tests, which are simulations made on computers, identify a system's reaction to selected credible emergency conditions. If the studies forecast system instability under specified conditions, plans or designs are changed to eliminate the problem.

Most of the regional councils have established criteria for testing bulk power systems, and the others are in the process of doing so, but identical guides will not necessarily be developed for all regions. Variations in test methods can exist and still provide system planners with information adequate to design systems of high reliability. Even if regions adopt uniform test procedures, some individual systems will need to apply other tests unique to their particular situations.

TABLE 15.1

Selected 1968 System Data for 147 Utilities Responding to Advisory Committee Questionnaire

Capacity of largest system	18,095 MW
Peak demand of largest system	15,266 MW
Largest thermal plant	1,978 MW
Largest thermal unit	995 MW
Largest hydro plant	2,400 MW
Largest hydro unit	175 MW
Sum of generating capacities of 147 systems	245,665 MW
Sum of nonsimultaneous peak demands of 147 systems	238,838 MW
Nonsimultaneous peak occurring in summer	62 %
Nonsimultaneous peak occurring in winter	38 %

Reported data relating to contingency tests were examined for similarities, and table 15.2 was prepared to summarize emergencies assumed in appraising system performance, more or less in descending order of probability and ascending order of severity. Most systems design to meet the first three or four single contingencies listed in table 15.2 without suffering thermal overload or instability, and to withstand any of the contingencies without widespread cascading.

Transient stability studies are extremely complex, but such tests have assumed greater multisystem importance with the installation of larger generating units and higher-capacity transmission lines. Many systems make a series of stability studies assuming singly or in various combinations such contingencies as a three-phase short circuit, loss of an entire plant, loss of multiple transmission circuits, or loss of an entire switching station, together with such operational contingencies as time-delay fault clearing, instantaneous clearing with automatic reclosing into a permanent fault, or an inoperative circuit breaker with clearing by backup facilities.

The majority of systems design their facilities to survive a three-phase fault cleared by primary relaying without developing system instability. Such faults are relatively rare, and this capability illustrates the high order of reliability that normally is designed into modern power systems.

Long-Range Planning Studies

In recent years, individual systems have extended the time periods covered by their long-range planning studies for bulk power system expansion because of the increasingly longer lead times required for installation of generating units and transmission lines, as discussed in the following sections and in chapter 16.

The advent of regional coordinating groups has not reduced the responsibilities of each individual system to conduct long-range planning studies for its own facilities. The regional organization's function is primarily to review these individual system plans for their effect on the reliability of the region and, when needed to initiate more comprehensive studies to assure that all plans, singly and combined, meet the reliability criteria of the region. Longer-range simulation studies are used to identify needs for future generation, transmission, and interconnection facilities.

Table 15.3 summarizes 1969 practices with respect to planning periods. The data, taken from reports of 135 systems, indicate the popularity of studies covering a six– to ten–year range. This reflects the fact that decisions for bulk power system additions must be made within about this time interval. The ten-year study period is also used frequently to evaluate alternative plans for economic studies. Every year, pursuant to FPC Order No. 383, all reliability councils report their plans for a ten-year period.

It is encouraging to note that a substantial number of the systems conduct studies for periods from 16 to 20 years in the future. It is increasingly apparent that new plant sites and line rights-of-way must be identified much earlier than generally has been done heretofore if

TABLE 15.2

Contingency Tests

Contingency Outage Tested	Percent of Systems Using Test
1 generator	56
1 circuit	76
1 generator and 1 circuit	40
2 generators	37
2 circuits	37
Double circuit tower	34
Right-of-way corridor	35
Complete transmission substation	25
Complete generator plant	35

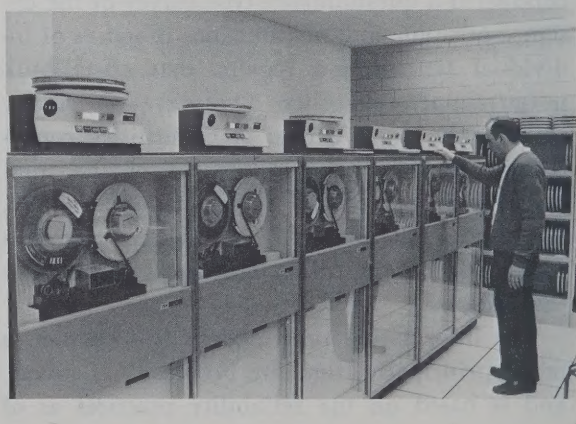

Figure 15.1—Data processing centers such as this one owned by Wisconsin Public Service Corporation are used by most electric utilities.

TABLE 15.3

Long-Range Planning Studies

Planning Period	Percent of Systems
Up to 5 years	8
6 to 10 years	59
11 to 15 years	9
16 to 20 years	21
21 to 25 years	3

the local problems are to be resolved so that construction can be completed in time to meet requirements of growing power system loads.

Lead Time for New Generating Units

Lead time in the delivery of ordered equipment has a direct relationship to system reliability, since delays in installation could mean inadequate spinning reserves or deficiencies in other items vital to the security of system operation. Lead time is dependent upon many factors, including public needs, attitudes, and desires; approvals by regulatory bodies; backlog of manufacturers' orders; and construction manpower problems.[1] Other more technical factors which affect lead time include unit size; whether the boiler, turbine, and generator are of an established or relatively new design; the type of turbine and generating equipment; and whether the unit is the first at a new plant site or an addition to an existing plant. Inadequate quality control in manufacturing and installation has also become a significant factor in the delays in achieving commercial operation of new equipment.

Although construction lead time allowances of approximately four years for large fossil-fired units have been satisfactory in the past, current experience indicates that lead times for all types of large steam-electric units are stretching into the six to eight year range. Utilities generally recognize these new conditions, but many currently authorized units were planned before the need for longer lead time became apparent, and delays of in-service dates of one to three years beyond those originally scheduled are commonplace. Significant delays may occur either before or after the major construction period. The early delays usually involve problems of public acceptance and regulatory clearance. The same problems may cause the later delays but more often terminal delays involve technical or physical problems with equipment.

In any case, the longer lead time is expensive for the consumer who must ultimately pay the bill. For example, if it is assumed that the investment in a $100 million installation is uniformly spread over a four-year period, the interest during construction at 7–½ percent per year is approximately $15,000,000. If the same investment is spread over eight years, the interest during the nonproduction period amounts to $30,000,000. Inflation, additional overhead, and other items such as heavy penalties in terms of charges for replacement energy and capacity also add costs as the lead time is extended. Delays for any reason are expensive; for a 1,000-megawatt plant they will normally cost more than a million dollars per month. Delays are also expensive in terms of technology. In periods of rapid technological change like those of the 1960's, and probably the 1970's, and particularly in the early years of use of new concepts such as nuclear generation, a plant which was designed greatly in advance of the date of commercial operation will not have incorporated in its construction many design improvements that are available by the time it is permitted to begin operation. In such case, time-consuming and expensive backfitting may be necessary or desirable.

Lead Time for New EHV Transmission Lines

One of the basic means of improving reliability and reducing the likelihood of area-wide power failures has been the strengthening of interconnections to permit adequate flow of power among neighboring systems. System design and operating practices have necessarily been modified to reflect this interdependence. Along with the expansion of interconnections, there has been the installation of larger generating units and higher voltage transmission lines with greater transfer capabilities, all of which contribute to increased economies and improved reliability of interconnected system.

In order to attain a high degree of reliability, it is essential that the important system elements, such as EHV transmission lines, be completed when they are needed. The causes of transmission line delays are primarily related to acquisition of rights-of-way, environmental ques-

[1] Chapter 16 treats the delay problem in more detail.

tions, and regulatory approvals. No systems reported delays because of equipment delivery or installation problems.

Increasing difficulties in obtaining rights-of-way, especially for EHV lines, are not unique to heavily populated areas. Difficulties have been experienced in less densely populated areas, particularly when proposed routes were near park lands, historic sites, or other areas of special scenic or recreational interest. Delays are generally related to environmental factors rather than rights-of-way price negotiations or other economic considerations.

Most systems reported that delays in placing transmission lines in service on schedule resulted in some degradation of reliability of service to customers, as vividly illustrated by past area power failures and more recently, by area load curtailments involving transmission system inadequacies. The desirability of minimizing intrusion on the environment and the need to utilize rights-of-way fully are apparent, but achieving these goals must be reconciled with the hazards which can result from either inadequate transmission or excessive concentration of critical circuits and the resultant increased exposure of systems to losses of large blocks of generating capacity. Continual efforts must be made to resolve these incompatible factors in the development of reliable transmission systems.

Communication Facilities

The need for adequate primary and alternative communication facilities between control centers and other important operating points of power systems is universally recognized. The more frequently utilized channels between control centers and major generating plants and switching centers are dedicated dispatch telephone circuits, independent teletype circuits, microwave radio, power line carrier, and mobile radio. About 98 percent of the major utilities have at least two independent communication systems. Communication channels between area control centers and regional coordination centers include principally teletype and local or long-distance telephone circuits, many of which are not integral to PBX equipment of power systems. About 70 percent of the reporting utilities have independent backup for the primary channels.

Attended or Remotely Controlled Substations

More than 60 percent of bulk power system substations are either attended or remotely controlled. Most of the other substations have automatic switching facilities designed to assure a reliable bulk power supply. Table 15.4 summarizes the response to this part of the questionnaire.

Emergency Power Sources for Control Centers

During the 1965 Northeast power failure, many system operations were severely hampered by the failure of power supplies providing essential services to control centers. Approximately 98 percent of the reporting systems now have emergency power sources to provide these services. Most utility systems conduct periodic starting tests to assure availability of these emergency power sources in the event they are needed.

Automatic Load Shedding

As late as mid-1967, relatively few electric utility systems utilized automatic load shedding to any significant extent, although earlier interruptions had indicated the probable usefulness of automatic load shedding in case of severe system disturbances causing subnormal frequencies, and the Commission had encouraged greater consideration of this means of protection against system collapse.

By 1970, the concept of automatic load shedding had gained relatively universal acceptance,

TABLE 15.4

Attended or Remotely Controlled Bulk Power System Substations

Percent of Substations Attended or Remotely Controlled	Reporting Systems	
	Number	Percent
90–100	94	64
80–89	8	6
70–79	6	4
60–69	5	3
50–59	5	3
40–49	3	2
30–39	3	2
20–29	7	4
10–19	4	3
0–9	8	6
No bulk stations	4	3

and 89 percent of the major United States systems had automatic load shedding facilities in operation or being installed. Although there are no universally used frequency set points at which automatic load shedding is initiated, the great majority of the systems do not initiate action until the frequency falls to 59.3 H_z. Generally, two- or three-step load-shedding plans are utilized, with the final step at 58.3 or 58.5 H_z. A few predominantly steam systems use more than three steps because of particular system security requirements. Predominantly hydro generating systems often utilize plans incorporating more than three steps, since hydro equipment is better able to sustain operation at lower frequency. The lower steps of these latter plans are in the range of 57.0 to 57.5 H_z. The blocks of load shedding at the higher frequency setpoints are usually smaller than in steam generation systems and larger blocks are shed at the lower frequency setpoints.

Load shedding is generally accomplished in blocks of 6 to 10 percent of system load. The total magnitude of load shedding generally varies between 25 percent and 35 percent of system load, although a number of predominantly hydro systems are capable of shedding considerably more. A brief summary of the status of automatic load shedding as reported in the NERC Survey for 147 systems is given in table 15.5.

The 45 reported occasions (a number of which are known to have been simultaneous) when systems experienced automatic load shedding do not indicate that the individual systems or groups of interconnected systems were inherently unreliable. On the contrary, the fact that only a few systems in the several regions experienced such events indicates that automatic load shedding is an emergency operating measure which limits or contains the area of potential cascading effect.

Some of the circumstances that have led to automatic load shedding include severe weather conditions, equipment failure, and human error. With limited exceptions, the areas affected and the magnitudes of load shedding were relatively small in comparison to total system demands immediately prior to the occurrences.

Several regions currently have fully coordinated automatic load-shedding plans in operation. Most other regions have adopted criteria for such plans, although the plans may not yet

TABLE 15.5

Automatic Load Shedding 1969

Load Shedding Plans	Number of Systems
Automatic load shedding in service	122
Automatic load shedding currently being installed	9
Number of steps in automatic load-shedding plans:	
One	7
Two	21
Three	74
More than three	20
Percent of load shedding at the following frequencies:	
Above 59.3 Hz.	
0–5	2
6–10	4
11 Up	2
59.3 Hz.	
0–5	11
6–10	67
11 Up	9
59.1 Hz.	
0–5	1
6–10	4
11 Up	2
59.0 Hz.	
0–5	7
6–10	50
11 Up	14
58.9 Hz.	
0–5	2
6–10	23
11 Up	4
58.7 Hz.	
0–5	7
6–10	40
11 Up	16
58.5 Hz.	
0–5	6
6–10	34
11 Up	11
58.3 Hz.	
0–5	0
6–10	6
11 Up	2
Below 58.3 Hz.	
0–5	3
6–10	5
11 Up	16
Systems which had experienced automatic load shedding	32
Number of automatic load-shedding occasions	45

be fully operative. It is also apparent that a number of adjacent regions have, to some extent, coordinated their automatic load-shedding plans.

Interruptible Loads

About one-third of the reporting systems have contracts which provide for interrupting selected loads with little or no prior notice. Such loads can serve as an alternative to operating reserve generating capacity. The customer inducement for using this type of service is a rate schedule that provides power at reduced prices. Over half of the systems serving interruptible loads have less than 2 percent of their total demand in this type of load. Only six systems had contractual interruptible loads greater than 10 percent of their total demands, and the largest amount reported by any system was 19 percent.

The merits and values of interruptible loads in terms of reliability are dependent upon the speed at which loads can be reduced. For use as a daily operating reserve, short-time interruptibles may provide capability at a faster rate than can be obtained by bringing up unloaded capacity or placing other capacity on line. Interruptible loads that require notice well in advance are not useful for immediate emergencies, but they can serve to make extra capacity available for firm loads during peak demand periods.

Interruptible service is not attractive to most power system customers, and many industrial processes do not lend themselves to interruptible services. Others who may not suffer substantial direct losses from power curtailments may find that savings attributed to lower electric rates do not always offset the expenses from loss of production and loss of labor during periods of curtailment. In some instances, however, such service at lower rates is attractive to particular industrial customers.

Table 15.6 shows the extent of interruptible loads reported by utilities in each of the National Electric Reliability Council areas.

Voltage Reductions

Although the Commission does not look favorably upon the use of voltage reduction as an ordinary operating procedure, it does recognize its usefulness where it can be employed as a temporary load reduction measure under emergency conditions of deficiencies in generating ca-

TABLE 15.6

Interruptible Loads [1]

Reliability Area [2]	Number of Utilities By Percent of 1968 Peak Demand that was Interruptible				
	0%	1–2%	3–7%	8–10%	11–19%
ECAR	11	4	3		1
ERCOT [3]	6		3		
MAAC	6	2			
MAIN	8	3	1		
MARCA	17	4			
NPCC	16	3			
SERC [4]	4	4	1	1	1
SWPP	18	4		1	
WSCC	14	4	3		4
Total utilities	100	28	11	2	6

[1] For 147 utilities surveyed.

[2] The Reliability Area abbreviations used are as follows: ECAR—East Central Area Coordination Agreement; ERCOT—Electric Reliability Council of Texas; MAAC—Mid-Atlantic Area Coordination Group; MAIN—Mid-America Interpool Network; MARCA—Mid-Continent Area Reliability Coordination Agreement; NPCC—Northeast Power Coordinating Council; SERC—Southeastern Electric Reliability Council; SWPP—Southwest Power Pool; and WSCC—Western Systems Coordinating Council.

[3] Originally known as TIS (Texas Interconnected Systems).

[4] Data for the Southeastern Electric Reliability Council (SERC) were reported by the independent members of NERC that have since organized SERC.

pacity. Significant reductions in delivery voltages frequently lead to customer dissatisfaction.

The ability to reduce voltage varies considerably from system to system. Voltage can be reduced more easily and effectively in limited geographical areas of high-load density. In the majority of cases, voltage reduction requires the dispatching of personnel to substations although some systems employ supervisory control equipment to perform the required functions. There are a few area-wide radio controlled voltage management systems in the United States.

Voltage should be reduced only when abnormal operating conditions within a total system or region cause a seriously low level of generating reserve. These conditions include multiple outages of generating capacity, limitations of transmission capability, and higher than anticipated demand due to weather sensitive loads. Generally, voltage levels are reduced 3 to 5 percent, but in some cases an 8 percent reduction is utilized. The load-limiting effect of voltage reduction is difficult to determine. During summer months, load reductions from ½ to 1 percent are reported to have been obtained from each percent of voltage reductions. During winter months, slightly greater reductions in load are obtained from the same decreases in voltage.

The Commission believes that voltage reduction should not be considered as a substitute for adequate reserve capacity, and that reductions of more than 5 percent should be avoided except in extreme emergency.

The number of systems employing voltage reduction procedures and the number of days from January 1, 1968, to about December 1969 that such measures were used are shown in table 15.7.

Reserve Practices

Individual systems and power pools utilize a variety of methods for determining appropriate reserve levels. The methods vary from use of a simple percent of peak load, to matching reserves to the capability of the largest unit or pair of units in service, to very complicated calculations of outage probability taking into consideration such elements as number and size of units, forced outage rates, and expected load patterns. Reserve margins considered adequate for most systems, including the spinning reserve component, range between 15 and 25 percent of peak load.

TABLE 15.7

Voltage Reductions January 1968 to December 1969 [1]

Number of Days Voltage Reduction Invoked	Number of Systems
1	2
2	3
3	2
5	4
6	1
7	3
9	3
11–20	2
21–30	11
41–50	4
51–60	2

[1] For 147 systems surveyed.

Each system, pool, or coordinating group develops spinning reserve criteria which it believes will show the minimum appropriate reserve for that particular power supply entity. Generally, the level of such reserve and its distribution among generating units takes into consideration the system characteristics and rate of required responses. The variations in practices reflect such things as differences in sizes and types of units, the number and capability of transmission interconnections, the geographical extent and configuration of a system, and pertinent operating agreements among interconnected systems.

Generation

It is essential to be able to shut down generating units safely during emergencies, or to provide facilities to enable their isolation on local loads or plant auxiliaries for short periods during an emergency so the units can remain in service and be immediately available to pick up loads. Isolation involves complex factors, such as the characteristics of system loads; area and geographic configuration of the system; location of generation plants with respect to load centers; boiler design characteristics; and the complexity of switching arrangements required to effect unit isolation.

The steam-electric generating capacity which can be isolated on local loads or unit auxiliaries

varies among the regional coordinating groups from approximately 2 percent to 100 percent of total capacity. These percentages alone do not indicate whether power systems are prepared to pick up load rapidly following correction of a power failure problem. More important is the ability to shut down safely and then restart the generating units in the event of complete loss of external ac service. More than 95 percent of steam-electric generating capacity in major plants is equipped for shutdown without damage to units in the event of loss of system power.

Safe shutdown and restart capability is often provided by the installation of on-site auxiliary generating facilities, such as gas turbines or internal combustion engines. Natural draft boilers, although not frequently used in modern power plants, and battery-operated pump equipment facilitate safe shutdown capability to a greater degree than some other designs.

A summary of the survey reports on safe shutdown and isolations of steam electric plants is given in table 15.8.

Between 49 and 99 percent of the total on-site emergency generating capacity in various regions is also used for peaking purposes. Emergency generating capacity is predominantly of the gas turbine type, usually because of its adaptability for peaking purposes and because of the larger ratings of such equipment in comparison to internal combustion engine units.

Hydroelectric generation may also be utilized in many instances for both startup power and peaking purposes. Regions having hydroelectric capacity frequently depend upon switching procedures to provide off-site startup power rather than providing on-site auxiliary combustion-type generation.

Table 15.9 shows, for the same generating capacity listed in table 15.8, the percentages of capacity with on-site emergency startup arrangements, the percent of the startup capacity which is used also for peaking purposes, and the percent of capacity for which there are specific switching facilities to provide use of off-site hydro or peaking plants as sources of startup power. It is recognized also that interregional assistance would be valuable in the prompt restarting of generation in an emergency.

Planned Separation of Generators in System Emergencies

During emergencies, separation of generators from the system may be necessary to prevent damage which might result from low frequency operation. Furthermore, isolation of generation at times of an imminent collapse of a generation-deficient island area may often expedite system restoration.

A general determination as to whether units are to be separated from the system is usually made before a subnormal frequency condition is encountered and takes into consideration manufacturers' recommendations related to turbine blading and other specific machine characteris-

TABLE 15.8

Safe Shutdown and Isolation Arrangements for Steam-Electric Plants, 1969

Reliability Region [1]	Total No. of Plants	Total No. of Units	Total MW Capacity	% Capability Arranged for Safe Shutdown	% Capability Arranged for Isolation
ECAR	106	421	42,554	98.0	73.6
ERCOT	48	154	16,937	95.7	86.3
MAAC	53	217	19,806	100.0	27.0
MAIN	53	199	20,673	97.2	26.8
MARCA	89	264	8,553	99.6	80.5
NPCC	79	302	24,748	98.0	39.4
SWPP	76	243	19,505	97.4	89.8
SERC	87	298	46,028	100.0	61.6
WSCC	60	208	23,298	96.7	96.7
Total or average	651	2,306	222,102	98.3	63.8

[1] See footnotes on table 15.6 for abbreviations and organizational changes since survey data were collected.

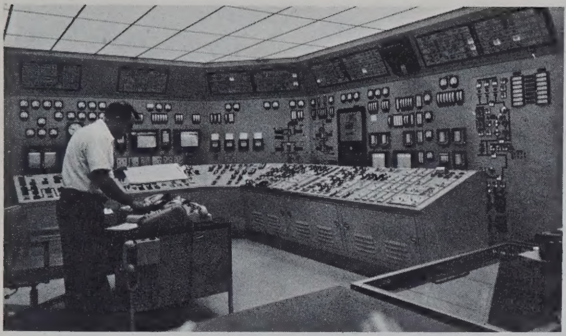

Figure 15.2—The control room for Dairyland Power Co-operative's 350-megawatt Genoa No. 3 plant.

tics. The final decision in most cases, however, is made by the plant or unit operator at the time a system disturbance occurs.

Approximately 94 percent of the reporting systems indicated they have plans for generator separation under subnormal frequency conditions. Fourteen percent of the systems use automatic controls for separation, and the most commonly used set points for this action are 58.5 and 58.0 H_Z. These same frequencies are also the ones most commonly specified in instructions to operators for initiation of manual separations. The information reported is summarized in table 15.10.

Six systems of 121 responding have installed oversized auxiliaries or other special features to permit some units to operate during emergencies at frequencies less than 60 H_Z.

Turbine Generator Maintenance Practices

Steam-turbines generally receive a careful inspection and overhaul about the end of the first year of operation to check compliance with manufacturers' warranties. Normal maintenance schedules then date from that time, with most systems scheduling major overhauls at intervals of four years, or more.

Reported information on turbine-generator maintenance schedules is summarized in table 15.11.

TABLE 15.9

Emergency Startup Power for Steam-Electric Plants, 1969

Reliability Region [1]	Percent of Capacity with On-Site Startup	Percent of On-Site Startup also used for Peaking	Percent of Capacity with Switching for Startup from Off-Site Hydro or Combustion Plants
ECAR	36.0	76.5	27.0
ERCOT	45.4	62.2	17.4
MAAC	82.3	98.4	33.0
MAIN	44.3	75.3	22.3
MARCA	13.1	49.6	42.2
NPCC	69.7	93.4	39.9
SERC	27.4	83.2	52.5
SWPP	29.2	82.2	22.7
WSCC	12.0	99.2	83.7
Average	40.1	84.9	39.2

[1] See footnotes on table 15.6 for abbreviations and organizational changes since survey data were collected.

TABLE 15.10

Generator Separation Plans

Reliability Region [1]	Number of Companies			
	Operator Action	Automatic Device	Not Designated	No Plan
ECAR	16	1	2	
ERCOT	9			
MAAC	6	2		
MAIN	10	1		
MARCA	14	4	1	2
NPCC	17			
SERC	9		1	1
SWPP	13	6		2
WSCC	6	4	4	3
Total	100	18	8	8

Separation Frequency	By Operator or not designated	By Automatic Device
60.0–59.0		1
58.9–58.0	52	10
57.9–57.0	16	4
56.9–56.0		
55.9–55.0		3
Not specified	40	
Total	108	18

[1] See footnotes on table 15.6 for abbreviations and organizational changes since survey data were collected.

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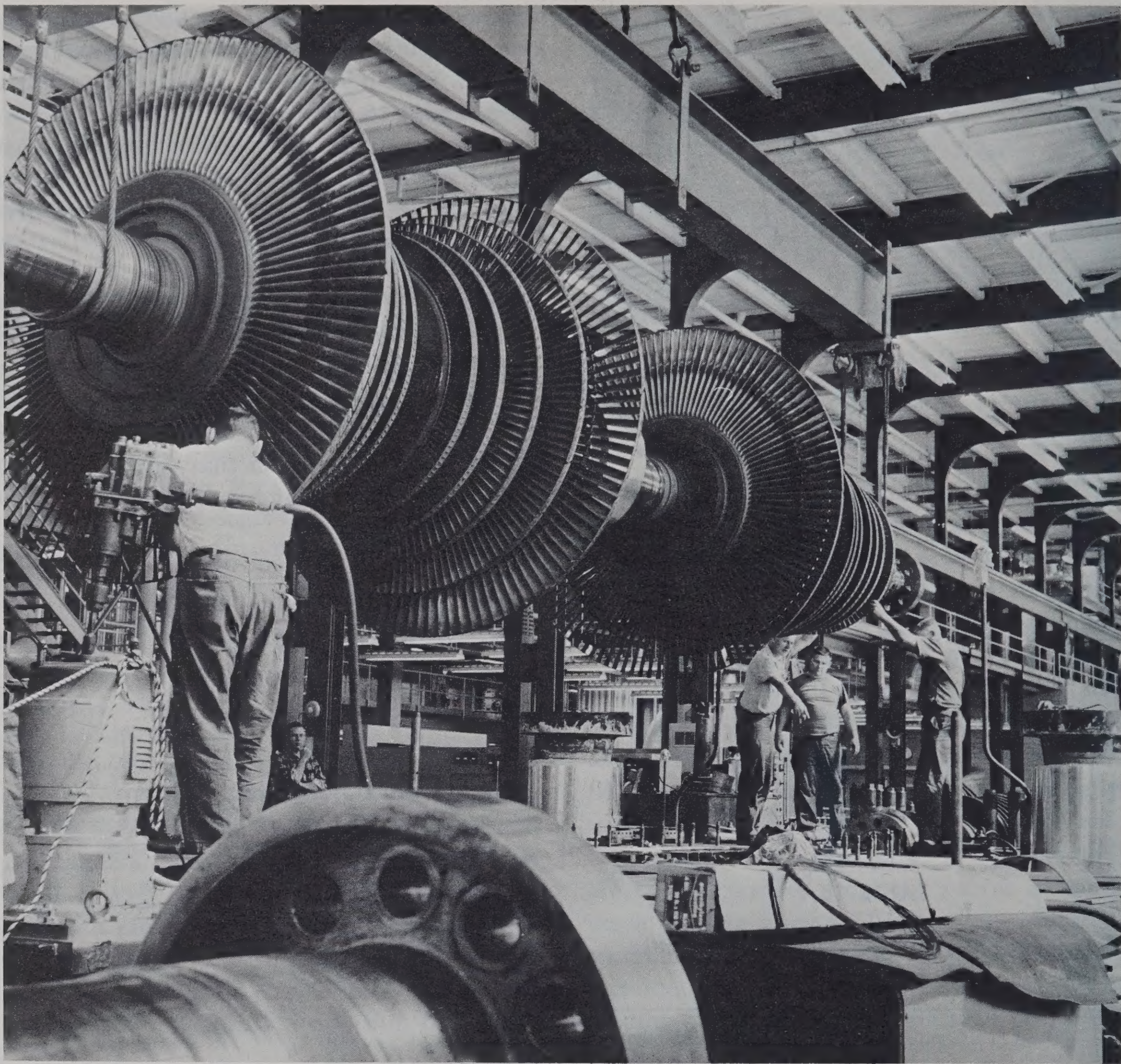

Figure 15.3—The turbine low pressure spindle and blading of Unit No. 3 at Florida Power Corporation's P. L. Bartow plant undergoing inspection and maintenance.

Bulk Power Transmission

Maintenance Schedules for Transmission Facilities

The frequency of transmission equipment inspections and maintenance is only a partial criterion by which to measure potential transmission reliability, but the general interest in transmission system maintenance schedules prompted the NERC Committee to survey industry practices in this field. Maintenance schedules vary among systems because of differences in both the manufacturers' recommendations and, more importantly, in operating experiences with particular pieces of equipment. General practices are summarized in table 15.12.

Helicopters and fixed-wing aircraft have proven to be valuable aids in patrolling transmission circuits, as shown in figure 15.4. In addition to usual inspections from the air, many systems are using infrared detection-type equipment to check the operating conditions of conductors and connectors. Generally, such inspections are scheduled for lines in high-load-growth

TABLE 15.11

Turbine-Generator Maintenance Schedules

	Reporting Systems	
	Number	Percent
Major maintenance inspections of steam turbines:		
1 year	5	4
2 years	5	4
3 years	15	11
4 years or more	103	77
Not scheduled [1]	5	4
Dielectric tests on generator windings:		
Under 1 year	2	1
1 year	42	31
2 years	12	9
3 years	8	6
4 years or more	52	39
Not scheduled [1]	19	14
Performance tests on generator automatic voltage regulators:		
Under 1 year	8	6
1 year	40	29
2 years	4	3
3 years	3	2
4 years or more	8	6
Not scheduled [1]	74	54

[1] While some systems do not schedule this maintenance on a time-interval basis, it is completed as necessary to maintain service reliability.

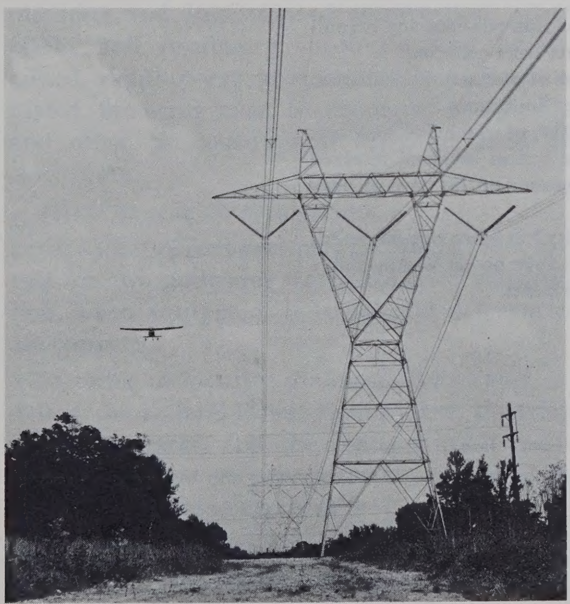

Figure 15.4—A fixed-wing aircraft patrolling a 500-kV transmission line of Gulf States Utilities Company.

TABLE 15.12

Transmission System Maintenance

	Reporting Systems	
	Number	Percent
Schedule for Maintenance Inspection of:		
Oil Circuit Breakers		
After specified number of faults	6	9
Annually	46	65
2–4 years	18	25
5 years	1	1
Gas Circuit Breakers		
After specified number of faults	5	12
Annually	27	63
2–4 years	10	23
5 years	1	2
Air Circuit Breakers		
After specified number of faults	5	8
Annually	37	62
2–4 years	17	28
5 years	1	2
Power Transformers		
Annually	69	73
2–4 years	22	23
5–6 years	4	4
Relays		
Annually	77	77
1–2 years	17	17
2–5 years	6	6
Grounding Switches		
Annually	36	82
1–3 years	8	18
Remote Signaling Equipment		
0–½ year	40	62
½–1 year	21	33
1–3 years	3	5
Use published guide or checklist to aid personnel in performing substation inspection:		
Yes	103	97
No	3	3
EHV Transmission Lines by:		
Aircraft Patrol		
1–6 weeks	45	39
7–12 weeks	3	3
Quarterly or less frequently	51	45
Not scheduled or not used	15	13
Ground Patrol		
0–½ year	30	33
½–1 year	38	42
2 years or more	6	7
Not scheduled or not used	17	18
Climbing Patrol		
Annually	5	5
1–3 years	6	5
4 years or more	16	15
Not scheduled or not used	81	75

or other areas where there is a known or potential loading that approaches line capabilities.

Maintenance Timing

Utilities generally schedule "Planned Maintenance" during seasons when loads are low. As more large generating units are added to systems, completion of maintenance during these periods will not always be possible because of the longer maintenance times required and the recent trend toward discovery of unforeseen problems after maintenance work is undertaken. The higher forced outage rates of newer units also increase the probability of systems having a substantial percentage of their capacity unavailable at the time of peak demand. Table 15.13 summarizes the unavailabilities of system generating capacity at time of annual peak for the systems reporting in each of the regional coordinating council areas.

TABLE 15.13

Unavailable Capacity at Time of 1968 System Peak

Region [1]	Number of Systems Reporting	Number of Systems with Unavailable Capacity at Time of Peak	Range of Unavailable Individual System Capacities [2] (% of System Total)
ECAR	19	14	[3] 0.7–36.9
ERCOT	9	2	5.2–15.7
MAAC	8	7	3.7–18.4
MAIN	12	4	2.9–12.9
MARCA	21	6	0.7–11.4
NPCC	19	11	[4] 0.8–71.8
SERC	11	9	0.3–17.9
SWPP	23	2	1.1–8.6
WSCC	25	6	0.3–14.4

[1] See footnotes on table 15.6 for abbreviations and organizational changes since survey data were collected.

[2] Capacity unavailable because of planned maintenance, forced outages, deratings or other limitations.

[3] The 36.9% represents 927 MW, of which 634 MW was the result of forced outage. The system involved received 672 MW from interconnected systems at the time of peak load.

[4] The 71.8% represents capacity lost when one large unit was forced out of service. Interchange power was available to meet system peak load requirements.

CHAPTER 16

PROBLEMS IN TIMELY PLANNING AND CONSTRUCTION OF NEW FACILITIES

Introduction

All segments of the electric utility industry are finding it increasingly difficult to make certain that generation, transmission, and distribution capacity is available to meet customer loads as they develop. The challenge of meeting customer demands is frequently complicated by delays that either originate or actually occur during the following four sequential periods.

(1) The forecasting period, when load projections must be prepared for 10 to 20 years into the future. These projections provide a realistic basis for planning to assure enough lead time for proper implementation of plans on a timely basis. General plans for the location and types of facilities are developed during this period.

(2) The clearance period, between general planning and initiation of construction, when public and regulatory approvals must be obtained, rights-of-way procurement must be completed, financing must be arranged, and design and other pre-construction activities must be carried out.

(3) The construction period.

(4) The shakedown period during the first year or two following completion of construction, when equipment is tested and deficiencies are corrected.

In order to identify the most likely causes of delays, the Federal Power Commission, state regulatory agencies, and the industry itself maintain records and prepare periodic analyses of industry performance and results.

Delays in Generating Equipment

The Federal Power Commission requested information from the Regional Electric Reliability Councils,[1] November 4, 1970, on problems (other than forecasting, category 1 above) which adversely affect the ability of individual utilities, power pools, and other utility groups to construct needed generation and transmission facilities in time to serve anticipated loads. The responses stressed the items listed below as major causes of delay, although the ranking varied somewhat among the regions.

1. Delays in obtaining permits, certificates, or licenses from local, state, and Federal agencies, sometimes because of backlogs or other intra-agency problems and sometimes because of protracted adversary proceedings.
2. Delays in delivery of major equipment from manufacturers, sometimes because of strikes or other labor-management problems at manufacturing or fabrication plants and sometimes because of lack of manufacturing capacity.
3. Rapidly changing standards and requirements for maintaining satisfactory air and water quality, resulting in major changes in design after construction is started.
4. Opposition from preservation, conservation, and environmental groups with concern over project impacts, and delaying tactics by opponents who are unwilling to accept the decisions of regulatory agencies.
5. Labor problems, such as strikes, demands for overtime, and low productivity at the construction site.
6. Quality assurance and control problems involving both basic materials and fabrication.
7. Siting problems, particularly for transmission lines and nuclear facilities.

A summary of installed capacity and the extent of known delays for the years 1966–1970 are shown in table 16.1. During the past five

[1] FPC Docket R–405.

TABLE 16.1

Summary of Capacity Installed and Capacity Delayed

	1966	1967	1968	1969	1970
Total capacity installed—MW	11,907	21,676	22,055	21,693	27,172
Capacity installed—large units, MW [1]	6,460	13,557	12,645	11,933	14,190
Large units on or ahead of schedule—MW	2,291	2,770	5,517	3,130	2,490
Large units delayed—MW	4,169	10,787	7,128	8,803	11,700
Percent delayed—total capacity	35.0	49.8	32.3	40.6	43.1
Percent delayed—large unit capacity	64.5	80.2	56.4	73.8	82.4
Capacity delayed 1–3 months—MW	2,953	4,706	5,007	3,095	2,574
Percent of total	24.8	21.7	22.7	14.3	9.5
Capacity delayed 4–6 months—MW		2,991	1,736	1,392	7,391
Percent of total		13.8	7.9	6.4	27.2
Capacity delayed 7–9 months—MW	393	1,350		1,833	1,083
Percent of total	3.3	6.2		8.4	4.0
Capacity delayed 10–12 months—MW	823	840	385		
Percent of total	6.9	3.9	1.7		
Capacity delayed over 12 months—MW		900		2,483	652
Percent of total		4.2		11.5	2.4

[1] 300 MW and larger.

years, the in-service dates of almost three-fourths of all new generating equipment were behind schedule.

The number of steam-electric units of 300 megawatts and larger that have been delayed during the 1966–1970 period and the reasons for the delays are summarized in table 16.2. Also similar information is shown for all large units scheduled for service after December 31, 1970, reflecting events that had occurred prior to January 1, 1971, that necessitated changes in the original in-service schedule. Since further delays or advancements may occur, the data for future installations are illustrative rather than definitive. Although the percentage of future units that face known delays is less than that of recently completed units, the potential for delays continues to be significant. It is discouraging to note that more than one-third of the units scheduled for completion after 1972 were already behind schedule at the beginning of 1971.

The effects of the types of delays portrayed in tables 16.1 and 16.2 are emphasized by the abnormal load reduction measures taken by some utilities and power pools in the United States during recent years. During the 1970 summer peak period, operating power pools curtailed service on 30 occasions, with the duration of the service reduction in major portions or all of the pool service areas ranging from 3 to 15 hours. In addition, single utilities reduced service on 19 occasions, for periods of 2 to 8 hours. During the 1970–71 winter peak period, pools reduced service 19 times, and individual companies curtailed service on 3 occasions.

Load reduction measures consisted predominantly of voltage reductions which had no serious or, in most cases, even noticeable effect on the customers. Such measures were generally instigated to provide acceptable reserve generating margins when high loads occasioned by weather extremes or abnormal forced outages resulted in a shortage of generating capacity that threatened to imperil reliability. Interconnected systems normally operate so that the interconnections are able to sustain deficient systems during both sudden and sustained emergencies. The resources of the interconnections were satisfactorily exploited in all recent emergencies, although transmission systems and interconnections among systems limited inter-utility and inter-regional transfers in some cases. In some instances the areas of deficiency were so large, geographically, that only partial assistance was

TABLE 16.2

Reported Delays in Schedules of Steam-Electric Generating Units, 300 Megawatts and Larger

	Number of Units Affected by Years								
	1966	1967	1968	1969	1970	1966–1970 Totals	1971 [2]	1972 [2]	1973 & Later [2]
Status of Units									
Units delayed	10	21	14	16	22	83	19	22	70
Units on schedule	1	3	6	4	3	17	23	28	121
Units ahead of schedule	4	3	4	2	1	14	5	10	15
Total number of units	15	27	24	22	26	114	47	60	206
Causes or Contributing Causes of Delays [1]									
Labor Related									
(1) Shortage of construction labor	4	6	5	6	4	25	1	5	2
(2) Reduced labor productivity		1		4	4	9	1	4	1
(3) Strikes	2	5	6	8	10	31	8	6	2
Subtotal	6	12	11	18	18	65	10	15	5
Other Causes									
(4) Equipment failure, faulty installation, start-up problems	3	9	5	7	5	29			
(5) Late delivery of equipment	1	5	3	5	3	17	6	6	4
(6) Inability to obtain necessary certifications and other regulatory impediments, including environmental problems		1	2	3	2	8	4	5	35
(7) Adverse weather	1				1	2	1		
(8) Planned deferments due to changes in load estimates		2				2	1		5
(9) Design changes					1	1		1	2
(10) Budget or financing problems							6	6	30
Subtotal	5	17	10	15	12	59	18	18	76
Total	11	29	21	33	30	124	28	33	81

[1] The same unit may be reported as delayed by more than one cause. Therefore, the sum of causes for delays may exceed the total number of units delayed.

[2] Status as of January 1, 1971.

available from neighboring utilities. In other cases extraordinary measures were invoked, such as the action requested of and taken by the Atomic Energy Commission during the period July 1-August 31, 1970, when it made 450 megawatts available for use throughout the interconnected systems. This was accomplished by the reduction of the power requirements at AEC's gaseous diffusion plants thus freeing that energy for transmission to supply-short areas.

While the value of strong interconnections is self-evident, it is inescapable that the basic trouble during recent years has been insufficient available generating capacity. There are practical operating reliability and economic limitations on the extent to which reasonably designed transmission systems can overcome major generating deficiencies throughout wide areas.

Delays in Transmission Construction

With a few significant exceptions, delays in meeting scheduled in-service dates for transmission lines have received little public attention. Since many new transmission facilities are associated with new generating plant additions, delays in plant construction may make transmission delays less critical. Also, most transmission

lines are built with some excess capacity to allow for future growth as well as emergency needs, so the urgencies of meeting schedules are not always as severe as for generating plants. It would be unwise to accept these circumstances as a premise for future planning, however, because there are some instances where transmission line construction delays have become as troublesome as generation delays in their effects on system reliability and stability. With the increase in transmission voltage levels, centralization of large blocks of generation, and long transmission lines crossing many jurisdictions, extended delays in installation of transmission can adversely limit inter-utility and inter-regional transfers as well as plant outputs. In the past, transmission delays usually caused relatively minor economic inconveniences and less than ideal generation dispatch. In the high voltage systems of today and tomorrow, delays in construction of transmission can be crucial. In one interconnected system, four major segments of a 500-kV backbone transmission grid have been delayed from 11 to 32 months, and none of the lines had final clearance at the end of 1970. Absence of these lines is already creating operating and economic problems, and service reliability will be seriously affected if the installations are not completed promptly.

Delays such as those discussed for the high capacity EHV lines between areas or systems or in high population density areas also plague smaller systems with lower voltage lines in less heavily settled areas. For over three years a 115 kV interconnection, five miles in length, has been delayed by the opposition of over 15 environmental and conservation groups in hearings before a State Public Service Board, as well as by numerous meetings between utilities and the affected town and regional planning commissions. Another system has encountered difficulty in obtaining the necessary rights-of-way for several 230 and 500 kV transmission lines, primarily because of increasing opposition related to environmental effects. The lines are critical, and failure to complete them soon could lead to service interruptions or curtailments in Washington and Oregon.

The opposition has not been directed against any one segment of the industry. Every segment —public, cooperative, and investor owned—has been plagued with delays. To obtain a better understanding of magnitude and geographical distribution of potential trouble spots, the Commission in 1970 made a survey to determine the delays experienced in high voltage transmission line construction schedules of the major electric utility systems in the United States. The results of that survey are summarized in table 16.3. The 3,659 circuit miles covered by the survey are equivalent to about 42 percent of the total mileage of high voltage transmission lines placed in service during the year ended June 30, 1970. The various causes of the delays are shown in table 16.4.

Financing Problems

The survey on which the preceding tables and discussions were based did not involve consideration of financing problems, except as noted. That subject is discussed in detail in chapter 20. It is mentioned here only to emphasize that

TABLE 16.3

Extent of Delays in High Voltage Transmission Line Construction for Lines Installed During Year Ending June 30, 1970

Design Voltage (kV)	Circuit Miles by Extent of Delay				Total Circuit Miles
	1–3 Months	4–7 Months	8–11 Months	12 or more Months	
230	31.2	162.1	47.7	583.5	824.5
345	95.7	185.8	230.2	147.6	659.3
500	382.0	402.7	36.8	296.0	1,117.5
765	90.7	0.0	116.0	0.0	206.7
800 dc	0.0	850.6	0.0	0.0	850.6
Total	599.6	1,601.2	430.7	1,027.1	3,658.6

TABLE 16.4

Causes of Delays in High Voltage Transmission Line Construction for Lines Installed During Year Ending June 30, 1970

	Circuit Miles by Type of Problem				
Design Voltage (kV)	Equipment	Design and/or Construction	Regulatory Certification or Permit	Coordination [1]	Fiscal [2]
230	87.0	142.3	145.6	8.3	441.3
345	90.1	158.4	198.3	212.5	0.0
500	398.0	71.8	321.4	0.0	326.3
765	0.0	144.0	0.0	62.7	0.0
800 dc	850.6	0.0	0.0	0.0	0.0
Total	1,425.7	516.5	665.3	283.5	767.6

[1] Involves cases where a portion of line is held up because of delays in another portion.
[2] Involves Federal lines dependent on congressional appropriations.

the problems of maintaining a financial climate conducive to investor support will continue to be extremely difficult unless many of the uncertainties that now face the industry are reduced or eliminated. Tremendous sums of money will be required to finance the facilities that must be built in the years ahead, and most of those funds will have to be provided by the investing public. The needed funds will be forthcoming only if the industry can demonstrate that its goals and objectives are stable, and that they can be met within an explicit financial framework. Unless the shifting targets of recent years can be stabilized, financing problems may become a major stumbling block in meeting future customer demands.

Scheduling Problems Related to Load Projecting

The difficulties of preparing load projections are discussed in chapter 3 and in the report of the Technical Advisory Committee on Load Forecasting Methodology printed in Part 4 of this Survey. The effects of load projections on construction scheduling are of concern in this chapter.

Load projections are used not only to indicate how much generating capacity must be built, but also to identify where it should be located, what types of capacity are needed, and what transmission will be needed to provide adequate and reliable service.

The simple planning objective of an electric utility—to meet each customer's electric energy requirements at the lowest possible cost consistent with the highest practical reliability and protection of the environment—belies the complexity of the process of meeting that objective. While it is customary, in the planning cycle, to relate the load obligation of a utility to the maximum demand made upon the generating facilities, the simple extrapolation of experienced loads into the future, according to some averaged rate of growth, may not provide an adequate basis for planning future generation and transmission. Thus, the planning process for utilities is a continuous one with plans constantly undergoing refinement as the power demand levels projected for future years are approached. Until recently, the time involved from announcement of the need for major steam-electric and transmission facilities to operation of those facilities rarely exceeded five years. The emphasis on load projections was for that period, even though load projections of longer range were often made for other purposes. There was little need for longer detailed plans since procurement, manufacturing, and construction processes worked well to meet schedules within that time span. By the early 1960's, however, it was apparent that the large units of the future, with their technological, logistical, and environmental complexities, could not be accommodated within a five-year projection framework. Estimating periods were extended and procedures refined, but in many

cases these changes came too late to avoid some imbalances between demands and supply that stemmed from inaccurate predictions of what loads would be.

Projecting loads involves not only the magnitude of loads, but also patterns of use within the maximum range of expected demands. During the past decade there has been a perceptible change in the characteristics of loads in many areas. While the consumer may be a captive of his electric energy supplier because of the nature of the industry and its regulation, he is not captive in his choice of manner or degree of use of the service. For example, with the advent of relatively inexpensive room air conditioners, many customers chose to install them in homes and offices, and the utilities found that their summer loads had suddenly increased dramatically and had become extremely weather sensitive. This is just one example of trends, or factors, that have until recently been evaluated only roughly, but that now call for more detailed and more sophisticated analyses because they have a pronounced effect on the determination of when, where, and what types of new facilities should be built.

The effects of load projections, good or bad, reach beyond the utilities into a separate and equally complex chain of events in the manufacturing and supporting supply industries. Manufacturers use load projections to develop their plans for new production capacity and for new equipment required to meet changing technology. Obviously, if the projections are inaccurate, the manufacturing capability is apt to be out of step with needs as they develop. In part, the recent widespread installation of gas turbines, with their shorter construction time, is a byproduct of some combination of inadequate load projections and delays in completing new steam-electric units.

Construction Clearances

The five-year planning-to-service interval for fossil-fueled thermal generation, mentioned above, served to conceal the fact that the true planning period was longer, even though it did not call for detailed long term load projections that now are needed. Many utilities owned plant sites for long periods of time, or at least had relatively specific areas in mind for future expansion where such things as water resources for cooling purposes had been evaluated. Study of the need for base load versus peaking units was a continuing process, as was the monitoring of fossil fuel prices, availability, and transportation costs. In many pool-type operations embracing two or more operating companies, other economic factors entered into management decisions. Since the role of management must always include the responsibility to provide economic as well as reliable service, and the competitive working of the American system was fittingly used to accomplish this, it has been considered proper and in the public good that the planning prior to construction time remain discretional with management. The declining cost of electric energy to the consumer during the past attests to the effectiveness of this system. Recent changes and other factors, however, have entered the picture, which now impose the necessity of altering the planning process without losing its past viability and economic effectiveness. For years many forward-looking individuals and organizations have been concerned with the effect of man and his activities upon his environment, and have advocated and pursued certain conservation measures. Much of the early activity centered around the preservation of wildlife species and was supported primarily by the sportsmen of America. Such factors as changes in technology and increases in population led to a new social consciousness in the post World War II society. This increasing interest in environmental protection permeated the political structure and includes many facets relating to air pollution, water pollution, noise pollution, land use, and esthetics.

Aside from those persons who had complained of fly ash fallout on their property adjoining coal-fired thermal plants, probably the first major impact upon the industry resulting from this growing concern to protect the environment involved esthetics at hydroelectric plants.

When Consolidated Edison Company of New York on January 29, 1963, filed with the Federal Power Commission its application for license to construct, operate, and maintain the proposed Cornwall pumped storage project, it was not unreasonable, based upon past experience, to expect that the license might be issued within a year or 18 months, thus permitting construction to start during 1964. Instead, after eight years

the matter is still unsettled, although the initial Federal Power Commission license was issued on March 9, 1965, and a revised license was issued on August 19, 1970, after court review and extensive rehearings. The Commission's decision has again been appealed. Prior to Cornwall, with few exceptions, the licensing and court review processes had not proven unduly burdensome to the industry and the planning time required by this process did not add objectionably to the lead time for most hydro projects.

While other factors were included, much of the controversy associated with the Cornwall project arose over esthetic problems of overhead transmission lines and the lack of public understanding of the technical and economic limitations on undergrounding transmission lines. The regulatory processes in America have been fundamentally quasi-judicial in nature and the success of the system has depended to a great extent upon a mutual understanding of underlying philosophy, an appreciation of the common goals and problems, and the expertise of the regulators and the regulated. Generally it had not been necessary to move into full judicial proceedings, which are inherently time consuming, and the small additional time element required to obtain a Federal Power Commission license for hydroelectric projects had been assimilated into the planning process. The industry's past experience with delays caused by such factors as right-of-way acquisition problems, even when going the complete judicial route, including exercise of eminent domain, had generally been solved in a concurrent time frame and had added little delay to timely completion of facilities.

By the time that the power of the atom was extended into peaceful uses, such as electric power generation, expertise and regulations of the Atomic Energy Commission had been well established. Their regulatory process, with safety the prime motivation, involves a construction permit phase (including a public hearing near the proposed site) and an operating permit phase. The time necessary for AEC's action on the utility's application for a construction permit must be included in total planning times. AEC's publication "Status of Central Station Nuclear Power Plants—Significant Milestones, March 1, 1971," lists 80 nuclear units for which construction permits have been issued. For these 80 units, the time from application to issuance of the construction permit ranges from a low of four months to a high of two and a half years, with an average time of 14 months. As of March 1, 1971, requests for construction permits had been filed but not yet granted for 26 additional units. The application for one of these units, with a date of November 1963, is in an inactive status; one, with a date of May 1968, has experienced excessive opposition; and the application dates for the remaining 24 units range from January 1969 to December 1970. Since companies have been waiting a year or longer as of March 1, 1971, for construction permits for over half of the latter 24 units, it appears that this time increment is increasing. Also, AEC's, quasi-judicial regulatory process appears to be facing increased time requirements involving drawn out adversary proceedings instigated, in the main, by public interest in environment protection, and significant additional delays may result from AEC's proposed regulations that have been issued subsequent to the decision of the United States Court of Appeals for the District of Columbia Circuit, July 23, 1971, regarding the Calvert Cliffs nuclear plant on the western shore of Chesapeake Bay, Maryland.

Interest in nuclear-powered generation rose dramatically in the mid-1960's, then diminished somewhat near the end of the decade because of several problems, uncertainties and delays. With a greater number of fossil-fueled thermal units being added than had been envisioned a few years earlier, the industry contributed to the dislocations which appeared in the raw fuel supply, transportation, and manufacturing industries. However, hopes of rapidly getting fossil-fueled units in service have been dimmed by added sequential events in the planning and development processes, including the sometimes almost impossible task of meeting moving targets of air and water quality standards while trying to design and order acceptable generating equipment. Because water resources are relatively fixed, the industry has already begun a move toward the use of supplementary cooling ponds and towers for large steam plants. While adding to both capital and operating costs, these supplemental cooling methods hopefully will satisfy most water quality standards.

The fossil-fuel-fired plant is at a particular disadvantage from the standpoint of air quality

control. The many entities involved and the time consumed in reaching decisions or satisfactory solutions sometimes create intolerable delays. Particulate discharge from coal-fired plants can be controlled with modern, highly efficient precipitators at added capital and operating cost penalties, and these facilities are being widely employed. Equipment that will satisfactorily control sulfur and nitrogen oxide wastes, is not available at this time, although solutions appear to be attainable within the current decade. The prescribing of low sulfur fuels, particularly gas and oil, can only be a stop-gap measure, even if costs were no object. The supply of low sulfur fuels is relatively limited, and therefore all-out efforts must continue in the development of reliable devices to control oxide wastes. In the interim, however, the state of the art must be recognized in establishing standards lest inflexibility cripples both the industry and the national economy.

Another environmental factor that could present a radical alteration to past planning practices involves esthetics. Since beauty has been said to be in the eyes of the beholder, that which presents an acceptable appearance is open to wide differences of opinion. Such differences could cause extensive delays and added costs which must be considered in the planning process. In considering possible power plant sites, it has been clearly demonstrated that early contact should be made with state and Federal agencies having regulatory control over various phases of plant construction and operation. With increasing competition for land, this problem can only become more significant in making resource-use decisions. There appears to be a need for simplified and coordinated regulatory procedures, including provisions for various public interests to be represented and for environmental values to be considered. This subject is treated in depth in the August 1970 report entitled "Electric Power and the Environment," sponsored by The Energy Policy Staff, Office of Science and Technology, to which the Federal Power Commission contributed. That report considers in detail possible alternative courses of action to overcome the inherent time-consuming workings of the quasi-judicial regulatory system. Revised judicial (or legislative) procedures may reduce the "lead time" assignable to this factor, but at the expense of building in a certain amount of inflexibility into expansion plans and possibly increased costs. Other alternatives may be preferable, or more acceptable to the public. It is sufficient here to say that a new time-controlling factor has been added to the planning process.

Problems During Construction

Virtually all utilities have complained, in recent years, about declines in labor productivity. This problem, although attributable partly to strikes and other deliberate job actions, reflects a lack of skilled labor and a possible decline in pride-of-accomplishment by the construction labor force.

Delays during the clearance stage, discussed above, result in new developments being behind schedule before actual construction gets underway. This situation is conducive to labor demands and strikes because the bargaining balance is upset by the pressure to get units completed without further delay. Recent shortages of skilled labor have substantially eliminated competition within the labor force, thus depriving management of a traditionally important bargaining point. The result has been a significant, although not necessarily deliberate, decline in productivity and a related increase in the difficulty of meeting construction schedules.

Changing technology has also presented problems for construction workers in recent years. Few construction workers have had experience with the large, complex equipment currently being built, particularly at nuclear plants. Basic training programs have been required in many instances, and proficiencies have had to be developed following training. The rapidly increasing amounts of capacity being constructed have created a situation where there is not enough experienced labor to go around, and have required the use of an abnormally high percentage of inexperienced workers. Labor as well as management has recognized the problem and has cooperated in training programs, optimum distributions of experienced workers, and other attempts to make the best possible use of available skills. Nevertheless, an appreciable amount of "slippage" is attributable to labor inexperience that results in both inefficiency and poor workmanship.

Another major cause of delays during construction is equipment failure stemming from

either manufacturing defects or faulty installation. In some cases the difficulties have stemmed from materials failures, but most problems are the result of poor quality control in the manufacturing or construction periods. Improved techniques for monitoring manufacturing and construction processes are constantly being developed, but much more needs to be done in this area.

Late delivery of equipment is a continuing problem. This factor involves not only manufacturing delays, but it also related to transportation delays and scheduling foul-ups. Shifts in emphasis from fossil to nuclear, then back to fossil and again to nuclear, have aggravated this problem, even though the shifts themselves have often been related to available manufacturing capacity. With the longer range projections now being prepared and a closer coordination between utility and manufacturer, these problems should become less troublesome.

Delays Following Completion of Construction

Many of the new units completed in recent years have not provided reliable service for months, or even years, after construction was presumed to have been completed. Delays in obtaining operating permits for nuclear plants have been a problem in a few cases; under recent court decisions and environmental regulations, this problem may become more widespread. The major problem, however, has been breakdown of equipment components during the testing and early operating period. To some degree, the problems are associated with new types of equipment associated with the large units now being constructed, and with environmental control facilities and other plant components that have not been perfected through use. In many cases, the problems have stemmed from the lack of adequate quality control, discussed above.

As experience is accumulated and control techniques are improved post-construction equipment outages should decrease, but with the constantly changing technologies envisioned for the future, it can reasonably be expected that the problem will be a continuing one and future plans and schedules should make specific allowances for such contingencies.

Considerations for Future Planning

Consistent and compatible standards for all types of environmental controls are urgently needed, particularly in contiguous areas with like ambient conditions. Without realistic and consistent standards, it is likely that facilities will be constructed in less restrictive jurisdictions, which may not be the best choice economically or operationally.

New standards should permit adjustments for facilities already under construction, so that state-of-the-art improvements in technology can be implemented when available and on realistic schedules. The electric utility industry can and should be a valuable contributor to a workable solution, but the basic thrust must come from the public, and from agencies or legislators with broad interests that encompass all types of enterprises whose operations affect the environment. Firm decisions must be made soon lest the current confusions become a prime delaying element. Increases in lead times can no longer be considered a practical or reasonable method of alleviating the problems of delay in areas where fundamental policy decisions are needed. There is no way to determine what lead times should be provided for as yet undetermined energy or fuel policies, or for the steadily mushrooming involvement of individuals and organizations with environmental concerns that sometimes immensely extends the regulatory process. Here the solution is not merely one of lengthening the time allowance for adversary proceedings, but rather one of fixing an order and time scale to assure due process. The efforts, including those of the Federal Power Commission, to meet this need equitably are discussed in detail in the previously mentioned report "Electric Power and the Environment". Generally, an annually updated ten-year load forecast and attendant construction program is called for, with the public advised of at least the general and larger elements. FPC Order No. 383–2, issued April 10, 1970, encourages this planning cycle as does the action of several state regulatory agencies, but the directive action necessary to eliminate the present chaos is still generally missing. Present thinking on the part of some would indicate that, before order and a realistic time scale can be incorporated into the planning process, legislative action, both Federal and

state, is necessary to provide equitable consideration of all interests in a combined, one-stop, regulatory-judicial process. While several Federal legislative proposals have been made embodying these general principles, none has yet been enacted. The State of New York on April 29, 1970, authorized this type of certification for certain high voltage transmission lines, and some other states have enacted some legislation along these general lines, but in most states numerous separate approvals must be obtained before construction can be undertaken.

There are many who think that, while the delays affecting transmission lines may be handled in this manner, the problems affecting siting of generating plants influence important questions relating to air and water quality and thus do not readily lend themselves to such control. Various proposed solutions to this problem include the action already taken by the Federal Power Commission which allows the costs of holding generating plant sites for long terms prior to construction to be included in the rate base and a 1971 law enacted in Maryland which provides that a state tax on electric energy and the revenues received from that tax be used to purchase sites for generating plants on a long-term basis, then selling them to utilities as they are needed. The principle underlying both methods is simply that the purchase date and holding time are so much ahead of the needed date that the public will have full opportunity to present its views with respect to the proposed land use before irrevocable decisions are made. Since this implies regulatory or judicial acceptance long before need, it minimizes site review as a delaying factor. The disadvantages to such procedures would be some loss of flexibility in considering alternatives or options in the planning process, but this could be outweighed by the monetary savings possible when plans are executed as needs develop.

CHAPTER 17

COORDINATION FOR RELIABILITY AND ECONOMY

Introduction

Nearly every major electric utility system in the United States is connected with neighboring systems to form large interconnected networks. The gradual evolution from small isolated systems in the early 1900's to groups of interdependent systems reflected the growing recognition by utility management that service reliability could be improved and the cost of providing service reduced through interconnection and coordination.

Financial benefits are often realized from staggered construction of large generating units, short-term capacity transactions, and interchanges of economy energy. Reduction of installed reserve capacity is made possible by mutual emergency assistance arrangements and associated coordinated transmission planning. Bulk power supply reliability is enhanced by interconnection agreements covering spinning reserves, reactive kilovolt-ampere requirements, emergency service, coordination of day-to-day operations, and coordination of maintenance schedules. Also, operating costs may be reduced through coordinated operation of interconnected systems.

The satisfactory performance of a power supply network requires close cooperation among component systems for accurate control of frequency, sharing of load regulating responsibility, and maintenance of power system stability. Many of the fundamental technical problems of interconnected operation were solved during the 1920's and 1930's, and that paved the way for a gradual extension of interconnections. Coordinated planning evolved more gradually because many independent systems had diverse characteristics and managements with widely differing attitudes toward the responsibilities of electric utilities. However, when it became evident that substantial economies were possible, coordinated planning gained greater acceptance and became more widespread. The increase in generator unit sizes and growth of high-capacity interconnected transmission systems in the United States during the past three decades (see chapters 5 and 13) are indications of the advantages of coordinated planning.

There are thousands of arrangements among systems from all segments of the industry providing for various degrees and metnods of electrical coordination. These variations reflect differences in load density, characteristics of generating resources, geography, and climate. They are also a product of managerial views with respect to planning, marketing, competition, and retention of prerogatives. Because of these differences, no single definition of coordination has been established by the electric utility industry. As used in this chapter, *coordination* is joint planning and operation of bulk power facilities by two or more electric systems for improved reliability and increased efficiency which would not be attainable if each system acted independently. *Full coordination* involves coordination of all systems within an area, to the extent technologically and economically feasible to permit the serving of their combined loads with a minimum of resources and to exploit opportunities for coordination with adjacent areas.

The highest degree of coordinated planning results when a group of utilities jointly plan, design, and construct their generation and transmission facilities as a single system. However, such coordinating groups must be large enough to take full advantage of the efficient generating units and EHV transmission made available by modern technology, yet be of manageable size with all members capable of sharing the responsibilities of the coordinated effort. Similarly, the highest degree of coordinated operation is

achieved when a group of utilities operate all of their bulk power facilities as a single system.

Most electric utilities are too small by themselves to construct and take full advantage of the largest modern fossil and nuclear fueled generating units, so they are able to obtain the economic benefits associated with large generating units only by joining with neighboring systems in coordinating arrangements.

Interconnection of electric systems throughout most of the nation has expanded the geographic area affected by equipment failures and generating deficiencies well beyond the boundaries of the utilities or pools which plan and install the bulk power facilities involved. The duration and extent of the November 9, 1965, Northeast power failure[1] caused concern throughout the Nation about bulk power supply reliability. Subsequent to the Northeast interruption, other system disturbances occurred which demonstrated that area-wide coordinated planning and operation, with effective regional overview, were needed to reduce the likelihood of power shortages and cascading failures. Electric utilities responded to this need by forming coordinating organizations for the express purpose of improving reliability on a regional basis. These regional reliability organizations do not have decision-making responsibilities for new facilities, but they do review the expansion plans of individual systems and coordinating groups. The large increase in electric power requirements anticipated during the next decade makes it imperative that electric utilities accelerate coordinated planning and operations in order to optimize the use of resources and to minimize the environmental impact of electric facilities.

Coordinating Organizations

Managements of various electric systems have developed a wide variety of formal and informal coordinating organizations or power pools. Some merely provide members with a mechanism for the exchange of information; others deal primarily with day-to-day interconnected operations under normal and abnormal system conditions; many engage in coordinated planning and operation for increased economies; and still others are dedicated to improving reliability over broad geographic areas encompassing otherwise unaffiliated electric systems. All of these organizations contribute in varying degrees to the reliability and economy of electric power supply.

The electric utility industry is responding to new opportunities for coordination by enlarging power pools through consolidation and expansion, by forming new ones, and by exploring the benefits possible from other types of joint endeavor. In short, there is a pronounced movement to broaden the scope of coordinating activities in an accelerated effort to achieve an appropriate balance among such important factors as reliability, economy, and environmental impact.

Formal Coordinating Organizations or Power Pools

The term "formal power pool" as used here means two or more electric systems which coordinate the planning and/or operation of their bulk power facilities for the purpose of achieving greater economy and reliability in accordance with a contractual agreement that establishes each member's responsibilities. Individual members usually are able to obtain the economies and other advantages available to much larger systems while retaining their separate corporate identities.

Growing acceptance of the power pool as a coordinating mechanism is indicated by the increase from 9, with 23 percent of the nation's generating capacity in 1960, to 22[2] with 60 percent of the capacity in 1970. Five of the pools are holding company groups, with membership consisting only of corporate affiliates. Power pools with corporately unaffiliated members increased from 4 to 17 in the 1960–1970 period and the proportion of generating capacity in the contiguous United States owned by these pool members increased from 12 percent to more than 50 percent. There are wide variations among the formal power pools in the number of systems participating and the geographic areas covered. Table 17.1 shows total generating capacity and peak-hour loads of the larger formal

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[1] Details of the Northeast power failure and associated problems are documented in the Commission's report of December 6, 1965, and in its three-volume report on the "Prevention of Power Failures," published in June 1967.

[2] The CARVA agreement was terminated on October 20, 1970, but some of the pool benefits will continue.

TABLE 17.1

Generating Capacity and Peak Loads of Formal Coordinating Organizations or Power Pools

	Generating Capacity as of January 1, 1971	1970 Peak-Hour Load	Nameplate Rating of Largest Generating Unit in Operation in 1971
	(MW)	(MW)	(MW)
NORTHEAST REGION			
New England Power Pool (NEPOOL) [1]	12,918	11,622	661
New York Power Pool (NYPP)	22,616	17,037	1,028
Pennsylvania-New Jersey-Maryland Interconnection (PJM)	29,899	23,838	936
Total for Region	65,433	52,497	
SOUTHEAST REGION			
Carolinas-Virginia Power Pool (CARVA) [2]	18,515	17,357	730
Southern Company System (Holding Company)	13,154	12,589	806
Total for Region	31,669	29,946	
EAST CENTRAL REGION			
American Electric Power System (Holding Company)	10,143	8,535	761
Allegheny Power System (Holding Company)	4,287	3,649	576
Central Area Power Coordination Group (CAPCO)	10,021	8,527	680
Kentucky-Indiana Power Pool (KIP)	4,899	4,157	518
Michigan Pool	10,605	8,905	750
Cincinnati, Columbus, Dayton Pool (CCD)	4,806	4,206	580
Total for Region	44,761	37,979	
WEST CENTRAL REGION			
Illinois-Missouri Pool	8,467	7,207	605
Upper Mississippi Valley Power Pool	5,991	5,305	580
Iowa Power Pool	2,614	2,582	212
Wisconsin Power Pool	1,845	1,755	406
Missouri Basin Systems Group (MBSG)	4,373	3,940	216
Total for Region	23,290	20,789	
SOUTH CENTRAL REGION			
Missouri-Kansas Pool (MOKAN) (excluding satellites)	4,739	4,287	495
Middle South Utilities System (Holding Co.)	6,753	5,999	700
South Central Electric Companies (SCEC) [3]	17,659	16,126	750
Texas Utilities Company System (Holding Company)	8,150	7,444	588
Total for Region [4]	29,009	26,487	
WEST REGION			
California Power Pool	20,340	18,077	755
Pacific Northwest Coordination Agreement	18,284	16,080	700
Total for Region	38,624	34,157	
Total for All Regions	232,786	201,855	

Source of generating capacity and peak-hour load data: Regional Council Reports and FPC Forms Nos. 12 and 12–E.

[1] Data for the nine systems which initiated NEPOOL studies in 1967.

[2] Pooling agreement terminated October 20, 1970, but the parties will adhere to principle of equalized reserves for an additional three-year period.

[3] Includes Middle South Utilities System power pool and two members of the MOKAN Pool with 8,292 MW of generating capacity and 7,369 MW of load.

[4] Duplication referred to in footnote 3 eliminated in totals.

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power pools located within each of the six National Power Survey regions [3]. Table 17.2 lists the individual members of each pool. The areas served by formal power pools cover most of the United States, as shown in figure 17.1.

Membership of most power pools consists entirely of the larger investor-owned systems, but the trend recently has been to include small privately and publicly owned and cooperative systems among their membership.[4]

Most of the holding company power pools and a few others, such as Pennsylvania-New Jersey-Maryland Interconnection (PJM) and Michigan Pool, are planned and operated as single systems. Others are less closely coordinated, but the degree of coordination, which generally reflects historic practices and management policies of the participating systems, tends to improve with time as the systems gain experience in working together.

Organizational Structures

Effective functioning of a power pool requires organizational mechanisms to establish reliability criteria and the responsibilities of each member for designing, constructing, and operating bulk power supply facilities. Generally, these tasks are accomplished through functional committees. The composition, responsibilities, and authority of the committees are usually outlined in the pooling agreement. In more highly developed pools the day-to-day operation, maintenance, and accounting may be handled by a pool manager and other full-time personnel.

Responsibilities of Pool Membership

Membership in a formal power pool imposes specific responsibilities upon each participant, among which are the following:

1. Providing capacity, either from its own system or by purchase, equal to the maximum demand of its system plus some additional amount for system reserve.
2. Providing some portion of the operating reserve [5] requirements of the pool either from its own resources or by purchase.
3. Maintaining its bulk power system in good operating condition.
4. Providing, operating, maintaining, and protecting the transmission and interconnecting facilities for its own system.
5. Furnishing, operating, and maintaining at its expense regulating facilities adequate to control frequency and interconnection loading within established limits.

Each of the parties must also furnish and maintain such communication and telemetering facilities as may be necessary. In those instances where the power pool has a single control area with free-flowing intra-system ties,[6] each of the members is allocated a portion of the expenses associated with operating the control area.

Sharing Reserve Capacity Requirements

A power pool must have sufficient generating capacity to meet the combined pool load plus reserve to cover equipment outages, frequency regulation, load swings, errors in forecasting loads, and slippage in planning and construction schedules. The various pools make specific provision for sharing among the pool participants the burden of providing this reserve margin. There are, in general, two different methods of acomplishing this objective. Under one, each member is required to maintain a specified minimum capacity reserve, usually stated in percent of peak load. Under the other, existing installed generating capacity is shared on an equalized reserve basis. That is, rather than each member being responsible for maintaining some minimum amount of reserve, the reserve capacity of the pool is shared proportionally among the members. Reserve responsibility is satisfied by capacity transactions so that members with excess capacity resources are compensated by members having capacity deficiencies.

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[3] Pools having more than 1,500 MW of installed generating capacity.

[4] For examples, New England Power Exchange (NEPEX), which implements single system dispatch of bulk power facilities in New England became operational on June 1, 1970. NEPEX consists of 11 investor-owned and 2 publicly owned utilities.

[5] Operating reserve is generating capacity in excess of load, connected to the system and ready to take load. It is normally divided into spinning reserve, which can take load immediately and ready or quickstart reserve which includes non-spinning generation that can be synchronized to the system and take load within 10 to 20 minutes. Some coordinating groups consider interruptible load to be a component of operating reserve.

[6] AEP, APS, Michigan, Middle South, New England, PJM, and Southern Company power pools.

TABLE 17.2

Members of Formal Coordinating Organizations or Power Pools

[January 1, 1970]

NORTHEAST REGION

New England Power Pool (NEPOOL) [1]

- Northeast Utilities [2]
- Boston Edison Company
- New England Electric System [2]
- Central Maine Power Co.
- The United Illuminating Co.
- Public Service Company of New Hampshire
- Eastern Utilities Associates [2]
- New England Gas & Electric Assoc.[2]
- Central Vermont Public Service Co.

New York Power Pool (NYPP) [3]

- Consolidated Edison Company of N. Y.
- Niagara Mohawk Power Corp.
- Long Island Lighting Company
- New York State Electric and Gas Corp.
- Central Hudson Gas & Electric Corp.
- Rochester Gas and Electric Corp.
- Orange and Rockland Utilities, Inc.
- Power Authority of the State of N. Y.

Pennsylvania-New Jersey-Maryland Interconnection (PJM)

- Public Service Electric and Gas Company
- Philadelphia Electric Company
- General Public Utilities Corporation
  - Metropolitan Edison Company
  - Pennsylvania Electric Company
  - Jersey Central Power and Light Company
  - New Jersey Power & Light Company
- Pennsylvania Power & Light Company
- Baltimore Gas and Electric Company
- Potomac Electric Power Company

SOUTHEAST REGION

Carolinas-Virginia Power Pool (CARVA) [4]

- Virginia Electric & Power Company
- Carolina Power & Light Company
- Duke Power Company
- South Carolina Electric & Gas Company

Southern Company System (*Holding Co.*)

- Alabama Power Company
- Georgia Power Company
- Gulf Power Company
- Mississippi Power Company

EAST CENTRAL REGION

American Electric Power System (AEP) (*Holding Company*)

- Appalachian Power Company
- Indiana & Michigan Electric Co.
- Kentucky Power Company
- Kingsport Power Co.
- Michigan Power Co.
- Sewell Valley Utilities Co.
- Wheeling Electric Co.
- Ohio Power Company

Allegheny Power System (APS) (*Holding Company*)

- Monongahela Power Company
- Potomac Edison Company
- West Penn Power Company

Central Area Power Coordination Group (CAPCO)

- Cleveland Electric Illuminating Company
- Duquesne Light Company
- Ohio Edison System (Holding Company)
  - Ohio Edison Company
  - Pennsylvania Power Company
- Toledo Edison Company

TABLE 17.2—Continued

EAST CENTRAL REGION—Continued

Cincinnati, Columbus, Dayton Pool (CCD)

Columbus & Southern Ohio Electric Co.
Dayton Power & Light Co.
Cincinnati Gas & Electric Co.

Kentucky-Indiana Power Pool (KIP)

Indianapolis Power & Light Co.
Public Service Co. of Indiana
Kentucky Utilities Company

Michigan Pool

Consumers Power Company
Detroit Edison Company

WEST CENTRAL REGION

Illinois-Missouri Pool

Central Illinois Public Service Company
Illinois Power Company
Union Electric Company

Upper Mississippi Valley Power Pool

Cooperatives
Cooperative Power Association
Dairyland Power Cooperative
Minnkota Power Cooperative
Northern Minnesota Power Assoc.
Rural Cooperative Power Assoc.
United Power Association

Investor-owned Companies
Interstate Power Company
Lake Superior District Power Co.
Minnesota Power & Light Company
Montana-Dakota Utilities Co.
Northern States Power Company
Northwestern Public Service Company
Otter Tail Power Company

Iowa Pool

Iowa Electric Light and Power Co.
Iowa-Illinois Gas and Elec. Co.
Iowa Power and Light Company
Iowa Public Service Company
Iowa Southern Utilities Company
Corn Belt Power Cooperative

Wisconsin Power Pool

Wisconsin Public Service Corporation
Wisconsin Power and Light Company
Madison Gas and Electric Company

Missouri Basin Systems Group (MBSG)

U. S. Bureau of Reclamation
Basin Electric Power Cooperative
Central Power Electric Cooperative
Nebraska Public Power System
Other Members

SOUTH CENTRAL REGION

Missouri-Kansas Pool (MOKAN) [5]

Empire District Electric Company
Kansas City Power & Light Company
Kansas Gas & Electric Company
Kansas Power and Light Company
Missouri Public Service Company

TABLE 17.2—Continued

SOUTH CENTRAL REGION—Continued

Middle South Utilities System (Holding Co.)

Arkansas Power and Light Company	Mississippi Power & Light Company
Louisiana Power and Light Company	New Orleans Public Service, Inc.

South Central Electric Companies (SCEC)

Gulf States Utilities Company	Arkansas Power and Light Company
Oklahoma Gas and Electric Company	Louisiana Power and Light Company
New Orleans Public Service Company	Mississippi Power and Light Company
Central Louisiana Electric Company	Kansas Gas and Electric Company
Public Service Co. of Oklahoma	Empire District Electric Company
Southwestern Electric Power Company	

Texas Utilities System (Holding Company)

Dallas Power & Light Company
Texas Electric Service Company
Texas Power and Light Company

WEST REGION

California Power Pool

Southern California Edison Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company

Pacific Northwest Coordination Agreement

Bonneville Power Administration	P. U. Dist. No. 1 of Chelan County, Washington
City of Eugene, Oregon	P. U. Dist. No. 1 of Cowlitz County, Washington
City of Seattle, Washington	P. U. Dist. No. 1 of Douglas County, Washington
City of Tacoma, Washington	P. U. Dist. No. 1 of Pend Oreille County, Washington
Colockum Transmission Company	P. U. Dist. No. 2 of Grant County, Washington
Montana Power Company	Puget Sound Power & Light Company
Pacific Power & Light Company	United States Corps of Engineers
Portland General Electric Company	Washington Water Power Company

[1] Data for the nine systems which initiated NEPOOL studies. As of January 1970, nearly all New England utilities were represented in the expanded negotiations which were in process since June 1969.

[2] Holding company.

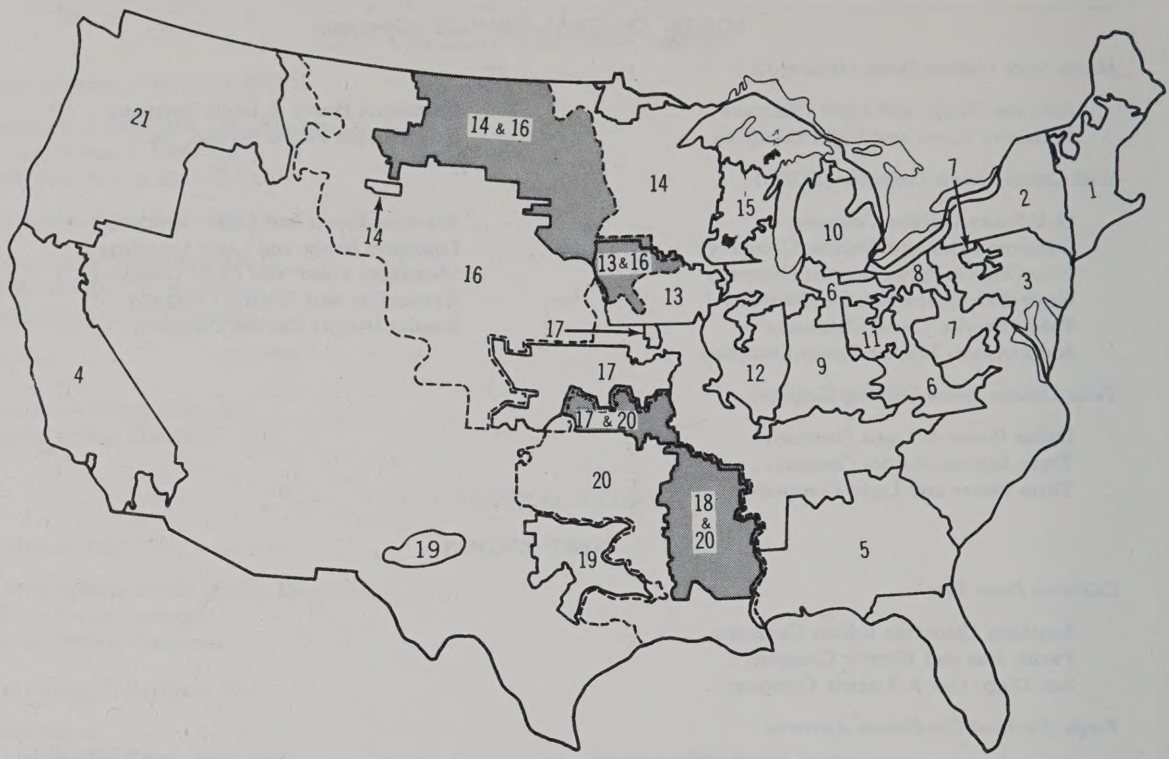
[3] Power Authority of the State of New York takes part in pool planning and operations, but not in commercial transactions of the pool.

[4] Pooling agreement terminated as of October 20, 1970.

[5] There are also five satellite members: St. Joseph Light & Power Co.; Board of Public Utilities of Kansas City, Kansas; City of Independence, Missouri; Central Telephone and Utilities Corp.—Western Power Division; and Associated Electric Cooperative, Inc.

Coordination of Operations

Most power pools have adopted a spinning reserve requirement equal to the size of the largest generating unit in operation. In addition, there usually is an operating reserve requirement equal to the pool's second largest unit or a fixed percentage of the load. Such capacity need not be spinning but must be capable of being synchronized and ready to pick up load within five to ten minutes. The most common pool practice is to distribute operating reserve responsibility among members in proportion to annual peak demands. In some instances, operating reserve is allocated on the basis of the annual peak load of each member or a ratio that reflects the peak load and the largest unit operated by each member. Some of the holding company system pools do not attempt to allocate operating reserve requirements among the corporate affiliates.



1. New England
2. New York
3. P-J-M Interconnection
4. California
5. The Southern Company System
6. American Electric Power System
7. Allegheny Power System
8. Central Area Power Coordination
9. Kentucky - Indiana
10. Michigan
11. Cincinnati, Columbus, Dayton
12. Illinois - Missouri
13. Iowa
14. Upper Mississippi Valley
15. Wisconsin
16. Missouri Basin Systems Group
17. Missouri - Kansas
18. Middle South Utilities System
19. Texas Utilities Company System
20. South Central Electric Companies
21. Pacific Northwest Coordination

NOTE: Not all systems operating in each of the 21 areas are formal power pool members.

Figure 17.1

Power pooling agreements usually provide for various types of transactions which taken together can achieve a pool generating pattern approximating that of a single system. Although there are numerous others, two of the most common of these transactions are emergency service and economy energy transfers.

Emergency service refers to the obligation of a pool member to supply energy to another pool member, or to an interconnected utility outside the pool, during an emergency outage of generation or transmission facilities. In the event of an emergency such as an unexpected generation outage, interconnections provide instantaneous assistance which may be furnished to the deficient system by others far beyond the boundaries of the power pool. Within seconds after an abrupt loss of generation, spinning reserves maintained by pool members begin to pick up load and replace the instantaneous assistance that was provided by loaded on-line equipment of pool members or interconnected systems. Ten minutes is generally considered a reasonable period for accomplishing a return to normal loading conditions of external pool ties.

Economy energy transactions in power pool

operations consist of sales of electric energy which any one pool party can produce and deliver to any other pool participant at an incremental cost lower than the incremental cost the receiving party would incur by generating or obtaining equivalent energy from other available sources. Pool agreements generally provide that a party is entitled to receive economy energy only to the extent that such participant has alternative dependable capacity available that would otherwise be used. Settlement for economy energy transactions between parties is commonly on a so-called "split-savings" basis where incremental, or added, costs of the supplying party, are subtracted from the decremental, or avoided, costs of the receiving party, and the difference is equally divided. The savings incurred through economy energy transactions are sometimes important elements in the economic justification of new interconnections.

The most sophisticated form of energy interchange is achieved through central economic dispatch of the generating resources of the systems comprising the pool. In this way, the combined generation of the pool can be operated to meet the combined pool loads at all times at the least cost, including the cost of transmission losses. A central dispatching headquarters must be established and arrangements made for the control of the various generating units and pool ties.

Coordination of Planning

The formation of a power pool is only one step in establishing an efficient bulk power supply system. The greater the degree of coordinated planning, the more management must subordinate its individual decisions relating to the bulk power supply. To some utility managers, this is a major obstacle to increased coordination, particularly in the early stages of a power pool. Also, corporate rate-base requirements, difficulty in allocating transmission system costs between power pool and individual system functions, reluctance to relinquish a particularly desirable generating site by one member for use of the entire pool, and a host of complex legal and organizational problems, including the apportionment of benefits among members of disparate size, are factors which have deterred some pools from attaining fully coordinated planning. There is, however, a trend toward area-wide coordination.

Informal Coordinating Organizations or Power Pools

There are at least 13 informal organizations of utilities in the contiguous United States which are structured to emphasize some limited aspects of inter-system coordination. These coordinating groups are informal in the sense that no member is contractually obligated to undertake any specific course of action or to provide any kind of service to other members. The groups are usually concerned primarily either with planning or operation, although some are active in both. The geographic areas covered by these groups are shown in figure 17.2. Table 17.3 lists each group, its acronym, and the individual members. Twenty-four individual systems, as shown in table 17.4, are members of two or more informal coordinating groups.

Planning Organizations

Only four of the 13 informal coordinating organizations are oriented essentially toward planning. As described in the following paragraphs, they serve different functions, but each provides a forum where members can explore the potential benefits of coordinated planning.

The primary purpose of Associated Mountain Power Systems (AMPS) is to study transmission interconnections with a view toward more efficient utilization of existing and planned generating capacity. As a result of these activities, members have contracted to build substantial transmission and interconnection facilities on a jointly planned basis.

In the Pacific Northwest, the Joint Power Planning Council (JPPC) has developed a coordinated power supply plan for installation of the large thermal base load and hydroelectric peaking plants that will be needed to meet the power requirements of the area through 1981. Commitments have been made for installing four thermal plants with a combined capacity of 5,100 megawatts. Two will be jointly owned by investor-owned and publicly owned utilities, one will be jointly owned by two investor-owned utilities, and the other will be owned solely by the Washington Public Power Supply System (WPPSS). Ninety-five cooperatives, municipals,

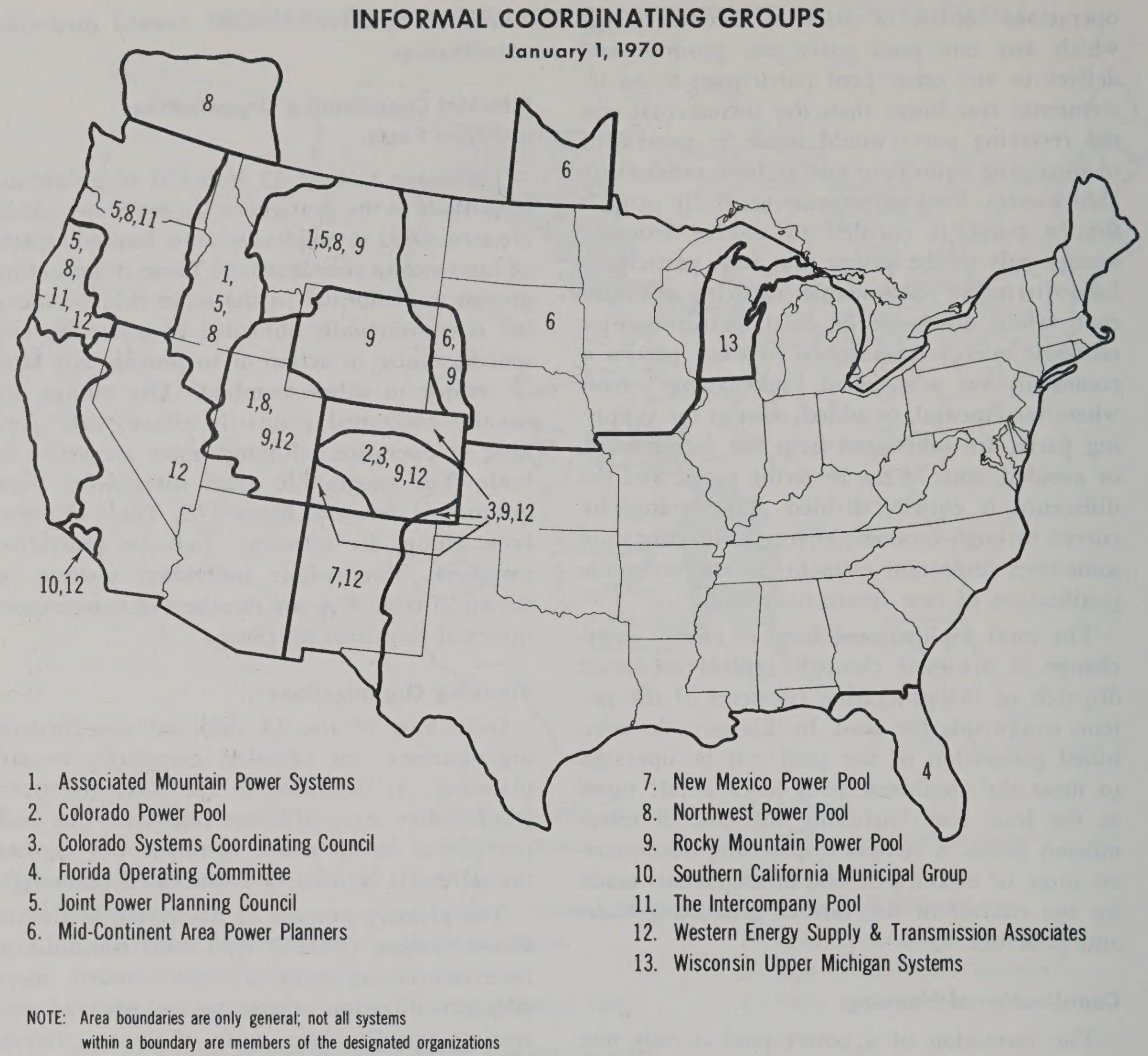


Figure 17.2

and public utility districts have contracted with WPPSS to purchase the output of this 1,100 megawatt plant. Three additional thermal plants of about 1,100 megawatts each probably will be jointly owned by investor and publicly owned utilities. Bonneville will obtain power from a number of the plants through contracts with public systems having ownership and/or purchase of output rights. Federal systems are expected to install 8,000 megawatts of hydroelectric peaking capacity, mostly at existing dams.

Mid-Continent Area Power Planners (MAPP) develops broad plans for expansion of generation and high capacity interconnections to reduce the cost and improve the reliability of electric service. Detailed planning for specific facilities is performed by individual systems or sub-area groups that will build and operate them; however, MAPP sponsors studies to determine generation reserve requirements and the savings available from coordinated operation. MAPP has a coordination center to improve the reliability and efficiency of day-to-day operations and to provide a focal point for emergency action when needed. MAPP is exploring procedures and organizational mechanisms to facilitate the formation of a large regional power pool.

TABLE 17.3

Informal Coordinating Organizations or Power Pools

[January 1, 1970]

PLANNING ORGANIZATIONS AND THEIR MEMBERS

Associated Mountain Power Systems (AMPS)

- Idaho Power Co.
- Montana Power Co.
- Pacific Power & Light Co.
- Utah Power & Light Co.
- Washington Water Power Co.

Total 5 Systems

Joint Power Planning Council (JPPC)

- Pacific Power & Light Company
- Portland General Electric Co.
- Puget Sound Power & Light Co.
- Washington Water Power Co.
- Bonneville Power Administration
- Publicly Owned Utilities in Oregon, Washington, Idaho and Montana (104 Systems)

Total 109 Systems

Mid-Continent Area Power Planners (MAPP)

- Black Hills Power & Light Co.
- Northwestern Wisconsin Electric Co.
- Omaha Public Power District
- Nebraska Public Power District
- Central Iowa Power Cooperative
- Eastern Iowa Light & Power Coop.
- Iowa Power Pool Members
  - Iowa Electric Light and Power Co.
  - Iowa-Illinois Gas and Electric Co.
  - Iowa Power and Light Co.
  - Iowa Public Service Co.
  - Iowa Southern Utilities Co.
  - Corn Belt Power Cooperative
- Union Electric Company
- Municipal Systems in Nebraska, South Dakota, Iowa and Minnesota (28 Systems)
- Manitoba Hydro-Electric Board
- Upper Mississippi Valley Power Pool
  - Cooperatives
    - Cooperative Power Association
    - Dairyland Power Cooperative
    - Minnkota Power Cooperative
    - Northern Minnesota Power Assoc.
    - Rural Cooperative Power Assoc.
  - Investor-owned Companies
    - Interstate Power Company
    - Lake Superior District Power Co.
    - Minnesota Power & Light Company
    - Montana-Dakota Utilities Company
    - Northern States Power Company
    - Northwestern Public Service Co.
    - Otter Tail Power Company

Total 54 Systems

Western Energy Supply & Transmission Associates (WEST)

- Arizona Public Service Co.
- Los Angeles Dept. of Water & Power
- El Paso Electric Co.
- Nevada Power Co.
- Public Service Company of Colorado
- San Diego Gas & Electric Co.
- Sierra Pacific Power Co.
- Southern California Edison Co.
- Tucson Gas & Electric Co.
- Utah Power & Light Co.
- Arizona Electric Power Coop.
- Public Service Co. of New Mexico
- Arizona Power Authority
- Burbank Public Service Dept.
- City of Colorado Springs
- Colorado-Ute Electric Association, Inc.
- Glendale Public Service Department
- Imperial Irrigation District
- Pacific Power & Light Co.
- Pasadena Municipal Light & Power Dept.
- Plains Electric G.&T. Coop., Inc.
- Salt River Project
- Central Telephone & Utilities Corp. (Southern Colo. Power Div.)

Total 23 Systems

OTHER INFORMAL COORDINATING GROUPS AND THEIR MEMBERS

Colorado Power Pool (COLOPP)

- Public Service Company of Colorado
- City of Colorado Springs
- Southern Colorado Power Div. of C.T.U.

Total 3 Systems

OTHER INFORMAL COORDINATING GROUPS AND THEIR MEMBERS—Continued

The Intercompany Pool (INTERPOOL)

Pacific Power & Light Company
Portland General Electric Co.
Puget Sound Power & Light Co.
Washington Water Power Co.

Total 4 Systems

Southern California Municipal Group (SCMG)

Los Angeles Department of Water and Power
Glendale Public Service Dept.
Burbank Public Service Dept.
Pasadena Municipal Light & Power Dept.

Total 4 Systems

Colorado Systems Coordinating Council (CSCC)

Central Municipal Light & Power System
Colorado Springs Dept. of Public Utilities
Town of Estes Park
Fort Collins Light & Power Department
City of Fort Morgan
Glenwood Springs Municipal Elec. System
Julesburg Power & Light Department
La Junta Municipal Utilities
Utilities Board of the City of Lamar
Las Animas Municipal Light & Power System
City of Longmont
Loveland Electrical Department
City of Trinidad
Colorado-Ute Electric Assoc., Inc.
Arkansas Valley G. & T., Inc.
Tri State G. & T. Assoc., Inc.
Home Light & Power Co.
Public Service Company of Colorado
Central Telephone & Utilities Corp. (Southern Colo. Power Div.)
Western Colorado Power Co.
USBR

Total 21 Systems

Florida Operating Committee

Florida Power & Light Co.
Florida Power Corp.
Tampa Electric Co.
City of Jacksonville
Orlando Utilities Commission

Total 5 Systems

Wisconsin-Upper Michigan Systems (WUMS)

Wisconsin-Michigan Power Co.
Upper Peninsula Power Co.
Wisconsin Power Pool (3 Systems)
Wisconsin Electric Power Co.

Total 6 Systems

Rocky Mountain Power Pool (RMPP)

Public Service Company of Colorado
Pacific Power & Light Co.
USBR Regions 4 and 7
Montana Power Co.
Consumers Public Power District
Southern Colorado Power Division of C.T.U.
City of Colorado Springs
Utah Power & Light Company
Black Hills Power & Light Co.
Tri-State G. & T. Assoc., Inc.
Colorado-Ute Elec. Association, Inc.
Cheyenne Light, Fuel & Power Co.
Western Colorado Power Co.

Total 13 Systems

New Mexico Power Pool (NMPP)

Community Public Service Company
El Paso Electric Company
Plains Electric G. & T. Coop.
Public Service Company of New Mexico
USBR Rio Grande Project

Total 5 Systems

TABLE 17.3—Continued

OTHER INFORMAL COORDINATING GROUPS AND THEIR MEMBERS—Continued

Northwest Power Pool (NWPP)

Bonneville Power Administration
Eugene Water & Electric Board
Idaho Power Co.
Montana Power Co.
Pacific Power & Light Co.
Portland General Electric Co.
Puget Sound Power & Light Co.
P.U.D. No. 1 of Chelan County
P.U.D. No. 1 of Douglas County
P.U.D. No. 2 of Grant County
Seattle Department of Lighting
Tacoma Public Utilities (Lt. Div.)
Utah Power & Light Co.
Washington Water Power Co.
British Columbia Hydro & Power Authority
West Kootenay Power & Light Co.
Corps of Engineers-North Pacific Div.
USBR–BPA (Southern Idaho)

Total 18 Systems

TABLE 17.4

Multiple Memberships in Informal Coordinating Organizations or Power Pools

System	NMPP	WEST	SCMG	CSCC	NWPP	RMPP	COLOPP	INTERPOOL	JPPC	AMPS	MAPP
El Paso Electric Co	X	X									
Public Service Co. of N.M.	X	X									
Plains Electric G. & T. Coop	X	X									
City of Los Angeles		X	X								
City of Glendale		X	X								
City of Burbank		X	X								
City of Pasadena		X	X								
Pacific P. & L. Co. (Wyoming)		X				X					
Utah Power & Light Co		X			X	X				X	
Public Service Co. of Colorado		X		X		X	X				
City of Colorado Springs		X		X		X	X				
Central Telephone & Utilities Corp. (Southern Colorado Power Division)		X		X		X	X				
Colorado-Ute Electric Association		X		X		X					
Western Colorado Power Co				X		X					
Tri-State G. & T. Association				X		X					
Bureau of Reclamation	X			X		X					
Portland General Electric Co					X			X	X		
Puget Sound Power & Light Co					X			X	X		
Pacific Power & Light Co					X			X	X	X	
Washington Water Power Co					X			X	X	X	
Bonneville Power Administration					X				X		
Idaho Power Co					X					X	
Montana Power Co					X	X				X	
Nebraska Public Power District						X					X

Western Energy Supply & Transmission Associates (WEST) is concerned primarily with achieving a more efficient use of energy resources within its geographic area. WEST neither constructs nor owns facilities but works with power suppliers within the area and in adjacent areas to coordinate system planning, utilize diversity, and reduce reserve capacity requirements. These activities have enabled several members to obtain economies of scale through participation in jointly owned generating plants and the construction of EHV transmission facilities.

Other Informal Coordinating Groups

The nine other informal coordinating groups, all in the southern or western parts of the country, generally limit their coordination activities to matters affecting system operation and service continuity. One delegates responsibility for dispatching to the member with the largest load. Most carry out cooperative studies of system stability and emergency load reduction procedures. Some gather data on system operations; make studies of system operation, interconnections, and the construction of bulk power facilities; review operating procedures to determine conformity with adopted recommendations; and recommend new or modified operating policies to insure closer coordination. One of the groups has established an Operating Committee to coordinate maintenance schedules to assure sufficient pool reserve capacity at all times; review load growth, maintenance work, and new construction on a bi-monthly schedule; and periodically review and coordinate relay settings which affect bulk power system reliability. Another allocates to each of its members a portion of the spinning and operating reserves required for the group as a whole in accordance with a pre-determined formula. Still another pool develops principles and procedures for controlling system frequency, interchange scheduling and accounting, maintenance scheduling, relay settings, communication systems, operating reserves, reactive resources, and, during low water periods, scheduling operations to optimize hydroelectric generation.

Electric Reliability Councils

Intensive studies of the Northeast Power Failure in 1965 demonstrated that, within the then-existent technology, individual system conditions could and did affect the interconnected system well beyond the boundaries of the problem area. It became clear that area and regional planning and coordination on a scale and in a depth that had not been practiced theretofore was required for reliable operation.

Utilities were quick to respond to this new challenge by initiating action to upgrade system facilities and to strengthen mechanisms for area and regional coordination. Two months after the disturbance, the major utility systems in New York and New England and the Hydro-Electric Power Commission of Ontario formed the Northeast Power Coordinating Council (NPCC) which was primarily concerned with improving the adequacy and reliability of bulk power supply.

The following year, the Federal Power Commission's Industry Advisory Committee on Reliability of Bulk Power Supply singled out regional coordination as "the most effective and economical means for assuring bulk power supply reliability for the Nation" [7]. Concurring with this view, the Commission recommended that ". . . strong regional organizations need to be established throughout the Nation for coordinating the planning, construction, operation and maintenance of bulk power supply" [8]. By the end of 1967, utilities had voluntarily established five coordinating councils to improve power supply reliability within their respective regions.

In June 1968, the industry took a further step in self-organization by forming the National Electric Reliability Council (NERC) to encourage improvement of coordination at both the regional and national levels. Its stated purposes are to:

1. Encourage and assist the development of inter-regional reliability arrangements among regional organizations, for their members;
2. Exchange information on planning and operation matters relating to the reliability of bulk power supply;
3. Review periodically regional and inter-regional activities on reliability;

[7] FPC *Prevention of Power Failures,* Vol. II, July 1967, p. 27.

[8] FPC *Prevention of Power Failures,* Vol. II, July 1967, p. 88.

4. Provide independent reviews of inter-regional matters referred to it by a regional organization; and
5. Provide information to the FPC and other Federal agencies

These five purposes are being reappraised periodically so that NERC can respond to the changing needs of regional councils, Governmental agencies, and the general public.

The 12 founder organizations of NERC consisted of the five regional coordinating councils plus three planning groups, two power pools, one investor-owned utility, and one large Federal electric system.

At the outset, utilities associated with NERC covered most of the contiguous United States. The only major geographic areas not represented were eastern New Mexico, extreme western Kansas, the Oklahoma Panhandle, the Texas Panhandle, southern Florida, and northern Maine. NERC-associated utilities in the contiguous United States had 239,981 megawatts of generating capacity and those in Canada 11,390 megawatts. Approximately 550 utilities with 25,000 megawatts or 10 percent of utility owned generating capacity in the contiguous states were not directly represented by the organizations which founded NERC.

Strengthened Reliability Councils

Following the formation of NERC, industry efforts were intensified to form new reliability councils and to expand membership in existing ones. The larger utilities in MAPP organized a separate reliability council and appointed a committee to formulate regional reliability criteria. By June 1969, parties to the Mid-Continent Area Reliability Council Agreement (MARCA) included 22 MAPP members and the Bureau of Reclamation. At the time NERC was formed, Missouri Basin Systems Group (MBSG), with 2,800 megawatts of generating capacity, was the only major power pool not represented. However, with the Bureau's membership in MARCA, MBSG achieved participation in reliability activities at both the regional and national levels. In January 1970, MARCA was admitted to membership in the National Electric Reliability Council as a successor to MAPP.

Broader regional participation is also being encouraged by other councils. During 1969, both the Northeast Power Coordinating Council and the Western Systems Coordinating Council established an Associate or Affiliate Member classification which permits municipal and other small systems to participate in council activities on a limited basis and with limited financial obligation. The Mid-Atlantic Area Coordination and the Mid America Interpool Network Agreements have been revised to include a similar provision. Also, members of the East Central Area Reliability Coordination Agreement (ECAR) instituted an agreement in April 1970 for indirect participation in ECAR by non-member utilities in the region through the formation of a Liaison Committee. In January 1970, the Southeastern Electric Reliability Council (SERC) was established. Every utility in the Southeast Region connected to the transmission grid and having at least 25 megawatts of generating capacity is eligible for council membership. Distribution systems throughout the region are represented by eight associate members. SERC is a successor to individual membership in NERC by CARVA Power Pool, Florida Power Corporation, Southern Company, and TVA.

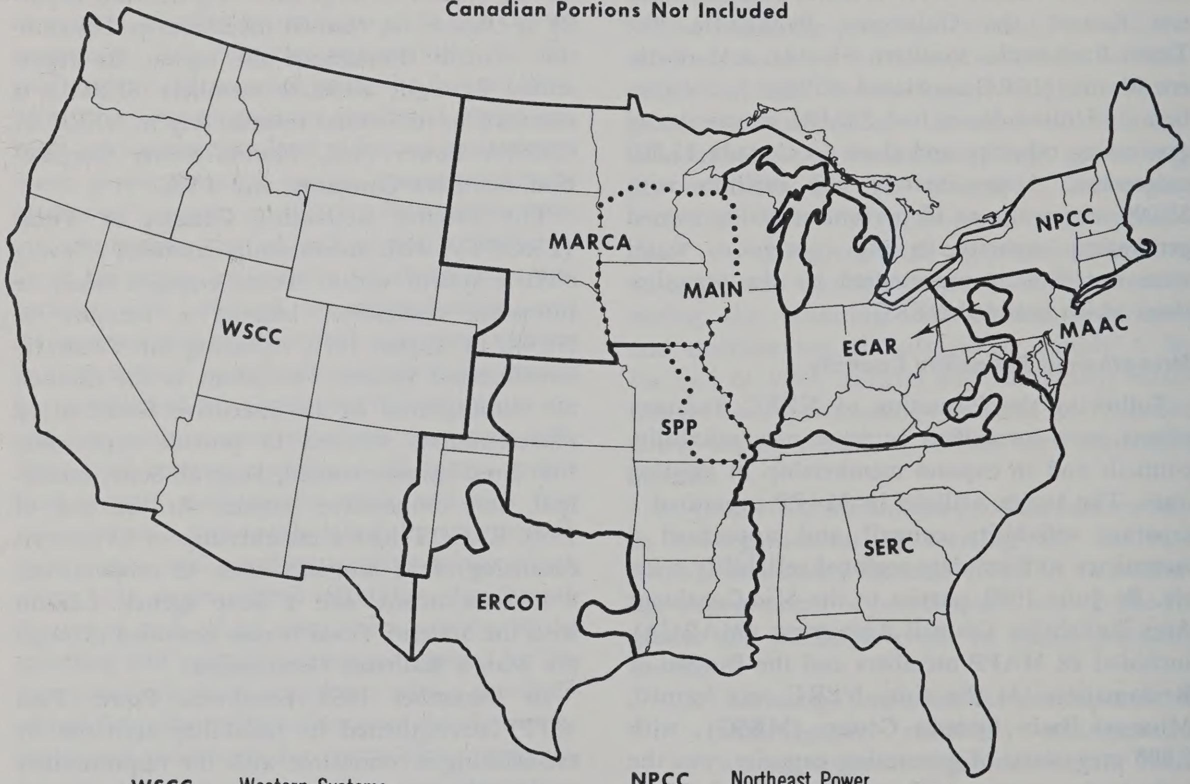
The Electric Reliability Council of Texas (ERCOT), with membership extended to every electric system within Texas engaged solely in intrastate commerce, became a member of NERC in August 1970, replacing the Texas Interconnected System. The affairs of the Council are administered by an Executive Board of 12 representatives selected to provide representation from investor-owned, Federal, State, municipal, and cooperative systems. At the end of 1970, ERCOT had a membership of 83 systems consisting of 32 municipalities, 42 cooperatives, 8 investor-owned, and 1 State agency. Liaison with the State of Texas is now provided through the State's Railroad Commission.

In December 1969, Southwest Power Pool (SPP) strengthened its reliability activities by establishing a committee with the responsibility to coordinate planning and operating matters and to develop reliability criteria for inter-regional planning. At the same time, membership requirements were modified so that any electric utility having at least one interconnection with the SPP transmission grid is eligible. Three cooperative and four publicly owned systems with a total of more than 1,500 megawatts of generating capacity became new members as soon as the modified agreement went into effect. Addi-

tional systems, principally in an area of west Texas not now covered by a reliability council, will become eligible for SPP membership in 1972, upon completion of a new 230 kilovolts transmission line from Elk City, Oklahoma, to Amarillo, Texas.

Thus, substantial progress in self-organization and consolidation has been achieved by the electric utility industry since the National Electric Reliability Council was formed in June 1968. The existing nine regional councils include virtually all major electric utilities in the 48 contiguous States and each council has established a mechanism to provide for direct or indirect participation by the smaller electric utilities within its boundaries. The approximate geographic boundaries of the councils are shown on figure 17.3. The generating resource totals reported by each council are listed in table 17.5 and the individual members of each council are shown in table 17.6.

None of the reliability councils has authority to make decisions involving the planning or installation of new bulk power facilities, but most have a formal review and approval role. Seven reliability councils have adopted criteria for testing the design and operation of existing and proposed bulk power facilities and the other two have established committees to formulate such criteria. Several councils have adopted pro-



WSCC	Western Systems Coordinating Council
MARCA	Mid-Continent Area Reliability Coordination Agreement
SPP	Southwest Power Pool
ERCOT	Electric Reliability Council Of Texas
MAIN	Mid-America Interpool Network
NPCC	Northeast Power Coordinating Council
MAAC	Mid-Atlantic Area Coordination Group
ECAR	East Central Area Reliability Coordination Agreement
SERC	Southeastern Electric Reliability Council

Figure 17.3

TABLE 17.5

Organizations Comprising the National Electric Reliability Council

Regional Organizations	Resources Winter of 1970 (Megawatts)
East Central Area Reliability Coordination Agreement (ECAR)	51,763
Electric Reliability Council of Texas (ERCOT)	20,942
Mid-Atlantic Area Coordination Group (MAAC)	29,151
Mid America Interpool Network (MAIN)	28,157
Mid-Continent Area Reliability Coordination Agreement (MARCA)	[1] 12,709
Northeast Power Coordinating Council (NPCC)	[2] 35,084
Southeastern Electric Reliability Council (SERC)	62,411
Southwest Power Pool Coordination Agreement (SPP)	25,413
Western Systems Coordinating Council (WSCC)	[3] 62,685

Source: Reliability Council Reports to FPC.

[1] Resources of Manitoba Hydro-Electric Board, Canada, not reported.

[2] Excludes resources of Ontario Hydro-Electric Commission, Canada, which are reported to be 11,908 MW.

[3] Excludes resources of the two Canadian members, British Columbia Hydro & Power Authority and West Kootenay Power & Light Co., which are reported to be 3,426 MW and 698 MW, respectively.

cedures for reporting by members of uniform compatible data on load estimates, scheduled maintenance, power exchanges, and installed reserve margins. A few have developed guides and regionally coordinated programs covering daily operating reserve margins, emergencies on the interconnected system, uniform rating of generating equipment, and principles of relaying. Some regional councils have established environmental committees to encourage more effective consideration of environmental matters in the siting, construction, and operation of major facilities.

NERC programs are carried out by the Executive Board and a Technical Advisory Committee (TAC) made up of officials and specialists from a membership that is broadly representative of electric utilities throughout the United States. TAC has responsibility for review and appraisal of inter-regional reliability coordination, technical advisory and informational exchange functions, liaison with the North American Power System Interconnection Committee (NAPSIC), and special projects relating to coordination of planning and operation.

Statement of Policy—FPC Docket No. R-362

The Commission's Statement of Policy on Reliability and Adequacy of Electric Service, Order No. 383–2 (Docket No. R-362), issued April 10, 1970, is intended to implement fully the voluntary aspects of Section 202(a) of the Federal Power Act,[9] and to encourage utilities throughout the Nation to continue to strengthen the reliability councils and develop more effective bulk power supply programs. The Commission Order requested participation by the staffs of the Commission and appropriate state commissions as non-voting participants in the principal meetings of NERC and the regional councils, and requested regional councils to report the projection of loads and coordinated bulk power supply programs on a ten-year basis. It also requested reports on the status of consultations with affected groups and appropriate local, State, and Federal authorities regarding the environmental impact of proposed major facilities, and information on load flow studies, network stability analyses, principal communication and control systems, and coordinated regional programs pertaining to provisions for emergencies, scheduled maintenance outages of major facilities, and other matters which affect the overall reliability of the interconnected network. Initial reports were filed as of September 1, 1970, and the second report from each council was filed on April 1, 1971. Future reports to be filed on April 1 of each year will provide opportunity for updating the power supply programs in the ten-year framework to reflect revisions in load

[9] Section 202(a) of the Federal Power Act states that for the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. Further, it shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.

TABLE 17.6

Individual Members of Regional Reliability Councils[1]

Northeast Power Coordinating Council (NPCC)

Boston Edison Co.
Burlington Electric Light Dept.
Central Hudson Gas & Electric Corp.
Central Maine Power Co.
Central Vermont Public Service Corp.
Consolidated Edison of N. Y., Inc.
Eastern Utilities Associates
Green Mountain Power Corp.
Hydro-Electric Power Comm. of Ontario
Long Island Lighting Co.
New England Electric System
New England Gas & Electric Assoc.
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
Northeast Utilities
Orange and Rockland Utilities, Inc.
Power Authority of the State of New York
Public Service Company of New Hampshire
Rochester Gas and Electric Corp.
The United Illuminating Company

Mid-Continent Area Reliability Coordination Agreement (MARCA)

Basin Electric Power Cooperative
Black Hills Power and Light Co.
Central Iowa Power Coop.
Cooperative Power Assoc.
Corn Belt Power Coop.
Dairyland Power Coop.
Eastern Iowa Light and Power Coop.
Interstate Power Co.
Iowa Electric Light & Power Co.
Iowa-Illinois Gas & Electric Co.
Iowa Power and Light Co.
Iowa Public Service Co.
Iowa Southern Utilities Co.
Lake Superior District Power Co.
Minnesota Power & Light Co.
Minnkota Power Coop., Inc.
Montana-Dakota Utilities Co.
Nebraska Public Power District
Northern Minnesota Power Association
Northern States Power Co.
Northwestern Public Service Co.
Omaha Public Power District
Otter Tail Power Co.
Rural Coop. Power Association
U. S. Bureau of Reclamation

Associates: Union Electric Co.
Manitoba Hydro-Electric Board of Canada

Southwest Power Pool Agreement (SPP)

Arkansas-Electric Coop. Corp.
Arkansas-Missouri Power Co.
Arkansas Power & Light Co.
Associated Electric Coop., Inc.
Board of Public Utilities, Kansas City, Kan.
Central Louisiana Electric Co., Inc. (The)
City Power & Light Dept., Independence, Mo.
City Utilities of Springfield, Missouri
Empire District Electric Co. (The)
Grand River Dam Authority
Gulf States Utilities Company
Kansas City Power & Light Co.
Kansas Gas and Electric Co.
Kansas Power & Light Co. (The)
Louisiana Power & Lt. Co.
Mississippi Power & Light Co.
Missouri Edison Co.[2]
Missouri Power & Light Co.[2]
Missouri Public Service Co.
Missouri Utilities Company
New Orleans Public Service, Inc.
Oklahoma Gas & Electric Co.
Public Service Co. of Oklahoma
St. Joseph Light & Power Co.
Southwestern Electric Power Co.
Southwestern Power Administration
Western Farmers Electric Coop.
Western Power Division—CT & U

Mid-Atlantic Area Coordination Agreement (MAAC)

Atlantic City Electric Co.
Baltimore Gas and Electric Co.
Delmarva Power & Light Co.
Jersey Central Power & Light Co.
Metropolitan Edison Co.
New Jersey Power & Light Co.
Pennsylvania Electric Co.
Pennsylvania Power & Light Co.
Philadelphia Electric Co.
Potomac Electric Power Co.
Public Service Electric and Gas Co.
UGI Corp.

Southeastern Electric Reliability Council (SERC)

Alabama Electric Cooperative
Alabama Power Company
Carolina Power & Light Co.
City of Tallahassee
Crisp County Power Commission
Duke Power Company
Florida Power Corporation
Florida Power & Light Co.
Georgia Power Co.
Gulf Power Co.
Jacksonville Electric Authority
Lakeland Dept. of Elec. & Water
Mississippi Power Co.
Nantahala Power & Light Co.
Orlando Utilities Commission
Savannah Electric & Power Co.
South Carolina Electric & Gas Co.
South Carolina Public Service Authority
Southeastern Power Administration
Tampa Electric Co.
Tapoco, Inc.
Tennessee Valley Authority
Virginia Electric & Power Co.
Yadkin, Inc.

East Central Area Reliability Coordination Agreement (ECAR)

Appalachian Power Co.
Cincinnati Gas & Electric Co.
Cleveland Electric Illuminating Co.
Columbus & Southern Ohio Electric Co.
Consumers Power Co.
Dayton Power & Light Company
Detroit Edison Company
Duquesne Light Company
East Kentucky Rural Electric Coop.
Indiana-Kentucky Electric Corp.
Indiana & Michigan Elect. Co.
Indianapolis Power & Light Co.
Kentucky Power Company
Kentucky Utilities Company
Louisville Gas & Electric Company
Monongahela Power Company
Northern Indiana Public Service Co.
Ohio Edison Company
Ohio Power Company
Ohio Valley Electric Corp.
Pennsylvania Power Company
Potomac Edison Company
Public Service Co. of Indiana
Southern Indiana Gas & Electric Co.
Toledo Edison Co.
West Penn Power Company

Mid-America Interconnected Network (MAIN)

Associated Electric Coop., Inc.[3]
Central Illinois Light Company
Central Illinois Public Service Co.
City Water Light & Power, Springfield, Ill.
Commonwealth Edison
Illinois Power Company
Interstate Power Company [5]
Iowa Electric Light & Power Company [4]
Iowa-Illinois Gas & Electric Co.[4]
Iowa Power & Light Company [4]
Iowa Public Service Co.[5]
Iowa Southern Utilities Co.[4]
Madison Gas and Electric Co.
Northern States Power Co.[4]
Union Electric Company
Upper Peninsula Power Co.
Wisconsin Electric Power Company
Wisconsin-Michigan Power Company
Wisconsin Power and Light Company
Wisconsin Public Service Corp.

Electric Reliability Council of Texas (ERCOT)

B-K Electric Coop., Inc.
Baird, City of
Bartlett Electric Coop., Inc.
Bluebonnet Elec. Coop., Inc.
Boerne Utilities
Bowie, City of
Brady Water & Light Works
Brazos Elec. Power Coop., Inc.
Brenham Municipal Utilities
Brownsville, City of
Bryan, City of
Cap Rock Elec. Coop., Inc.
Central Power & Light Company
City of Austin
City Public Service Board (San Antonio)
Coleman, City of
Comanche County Elec. Coop. Assoc.
Community Public Service Company
Crosbyton, City of
Cuero Electric Dept.
Dallas Power & Light Company
Deep East Texas Elec. Coop., Inc.
Denton Municipal Utilities
Denton County Elec. Coop., Inc.
DeWitt County Elec. Coop., Inc.
Fannin County Elec. Coop., Inc.
Farmers Electric Coop., Inc.
Fayette Electric Coop., Inc.
Garland, City of
Giddings, City of
Goldthwaite, City of
Gonzales Electric District System
Grayson-Collin Elec. Coop., Inc.
Greenville Municipal Utilities
Guadalupe Valley Elec. Coop., Inc.
Jackson Electric Coop., Inc.
Jasper-Newton Electric Coop., Inc.
Johnson County Electric Coop. Assn.

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Electric Reliability Council of Texas (ERCOT)—Continued

Kaufman County Electric Coop., Inc.
Kimble Electric Coop., Inc.
LaGrange, City of
Lamar County Electric Coop. Assn.
Limestone County Elec. Coop., Inc.
Livingston, City of
Lockhart Utilities
Lower Colorado River Authority
Luling Utilities
Magic Valley Electric Coop., Inc.
McCulloch Electric Coop., Inc.
McLennan County Electric Coop., Inc.
Medina Electric Coop., Inc.
Mid-South Electric Coop. Assn.
Midwest Electric Coop., Inc.
Navarro County Electric Coop., Inc.
New Braunfels Utilities
New Era Electric Coop., Inc.
Nueces Electric Coop., Inc.
Robertson Electric Coop., Inc.
Robstown, City of
Sam Houston Electric Coop., Inc.
San Bernard Electric Coop., Inc.
San Patricio Electric Coop., Inc.
Schulenburg, City of
Seguin, City of
Shiner, Light & Water Department
Southwestern Electric Service Co.
South Texas Elec. Coop., Inc.
Southwest Texas Elec. Coop., Inc.
Stamford Electric Coop., Inc.
Teague, City of
Hamilton County Elec. Coop. Assn.
Hearne Municipal Plant
Hemphill Electric Department
Hill County Electric Coop., Inc.
Houston Lighting & Power Company
Hunt-Collin Elec. Coop., Inc.
Texas Electric Service Co.
Texas Power & Light Co.
Tri-County Electric Coop., Inc.
Tulia Light & Power Plant
Weimar, City of
West Texas Utilities
Wise Electric Cooperative, Inc.

Western Systems Coordinating Council (WSCC)

Arizona Power Authority
Arizona Public Service Co.
Bonneville Power Administration
British Columbia Hydro & Power Authority
California Dept. of Water Resources
Central Telephone & Utilities (South Colorado Power Division)
Chelan County P.U.D. No. 1
City of Glendale, Public Service Dept.
City of Tacoma, Dept. Public Utilities
City of Seattle Dept. of Lighting
Cowlitz County P.U.D. No. 1
Colorado—Ute Electric Association, Inc.
Douglas County P.U.D. No. 1
El Paso Electric Company
Eugene Water & Electric Board
Grant County P.U.D. No. 2
Idaho Power Company
Los Angeles Department of Water & Power
Metropolitan Water Dist. of South Calif.
Montana Power Company
Nebraska Public Power District [4]
Nevada Power Company
Pacific Gas & Electric Co.
Pacific Power & Light Company
Portland General Electric Co.
Public Service Company of Colorado
Public Service Company of New Mexico
Puget Sound Power & Light Co.
Sacramento Municipal Utility District
Salt River Project
San Diego Gas & Electric Co.
Sierra Pacific Power Company
Southern Calif. Edison Company
Tri-State G&T Association
Tucson Gas & Electric Company
U. S. Bureau of Reclamation
U. S. Corps of Engineers
Utah Power & Light Company
Washington Water Power Company
West Kootenay Power & Light Company

[1] Membership reported by all electric reliability councils as of September 1, 1970, except for the Electric Reliability Council of Texas which is reported as of November 20, 1970.

[2] Also members of MAIN through their parent company, Union Electric Company.

[3] Also member of SPP.

[4] Also member of MARCA.

[5] Member of MARCA. Resigned membership in MAIN as of June 30, 1971

estimates, new developments and resources, and the resolution of environmental issues.

North American Power Systems Interconnection Committee

In April 1962, representatives of interconnected systems throughout the United States and eastern Canada met at Omaha, Nebraska, and laid the groundwork for an international organization to coordinate the operation of a looming coast-to-coast interconnected network. This led to formation of the North American Power Systems Interconnection Committee (NAPSIC) which held its first meeting in January 1963. NAPSIC is a voluntary organization of operating personnel representing ten interconnected Operating Areas. Although the geographic boundaries of a few of the Operating Areas have been adjusted since 1963, the number has remained the same. The areas, as of January 1, 1970, are shown on figure 17.4.

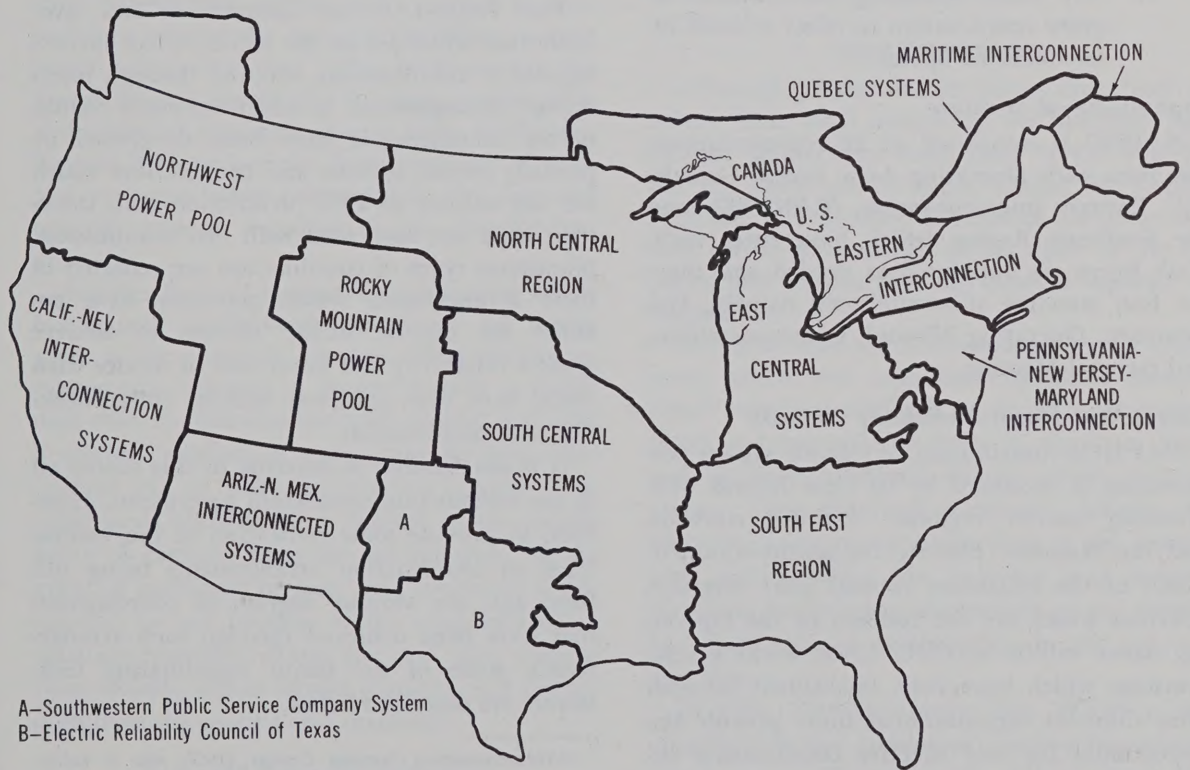
Purpose and Scope

At the outset, the principal goals NAPSIC set for itself were to coordinate frequency, operating criteria related to time error, and tie-line bias settings. Its first Operating Manual was published in September 1964. By January 1968, the number of guides included in the Operating Manual had increased from 9 to 20. The guides establish general criteria which, although not explicit enough to be used as detailed specifications for system operation, enunciate generally accepted principles and codify minimum operating criteria for coordinated operation.

The purpose and scope of NAPSIC were restated during 1969 to recognize the accelerating pace of interconnections and the increased coor-

NORTH AMERICAN POWER SYSTEMS INTERCONNECTION COMMITTEE AREAS

January 1, 1970



A–Southwestern Public Service Company System
B–Electric Reliability Council of Texas

Areas A and B are represented in NAPSIC by the South Central Systems, but are not in synchronous operation with the interconnected power systems in the South West Region

Figure 17.4

dinating activities which had already occurred. At that time, NAPSIC resolved to maintain itself as an effective interconnected systems operation organization, and to accept responsibility for useful liaison with other organizations. The scope of the organization was expanded so that by 1971 it included consideration of the following:

1. Operating reliability criteria,
2. Frequency regulation,
3. Time control,
4. Tie-line frequency bias,
5. Operating reserves,
6. Time error correction procedures,
7. Emergency operating procedures
   (a) Load shedding and restoration
   (b) Tie separation and restoration
   (c) Generating unit security,
8. Scheduled maintenance outages of major facilities,
9. Interchange scheduling procedures,
10. Procedures for handling inadvertent interchange,
11. Any other operating matters that require coordination to effect reliable interconnected operation.

Organizational Structure

NAPSIC is comprised of 22 representatives: two from each Operating Area, except Canada-U.S. Eastern Interconnection (CANUSE) and the Southeast Region which have three each. Task forces are appointed as needed and there are four standing subcommittees; namely, Performance, Operating Manual, Communications, and General Meeting.

Liaison With Electric Reliability Councils

NAPSIC's contribution to reliable system performance is enhanced by its close liaison with planning entities, regional reliability councils, and the National Electric Reliability Council. Much of the reliability council work overlaps activities which are the concern of the Operating Areas within NAPSIC. Close working relationships which have been established between these different organizational units provide the opportunity for very effective coordination between planning and operating functions. The activities of most Operating Areas in NAPSIC are expected to be integrated with the Councils in NERC. One exception is the area of the South Central Systems which formerly was the Southwest Region (a subdivision of the recently disbanded Interconnected Systems Group[10]). This NAPSIC Operating Area probably will continue to have its operating procedures coordinated on a regional scale until a more comprehensive regional entity is established. At the national level, NAPSIC has a representative on the NERC Technical Advisory Committee.

Coordinating Techniques

Over the years electric utilities have developed a wide variety of coordinating techniques to achieve increased reliability and improved economies. The increased emphasis on area-wide coordination during the latter half of the 1960's has accelerated the utilization of bilateral and multi-party agreements. In the absence of pool-wide procedures for achieving full coordination, individual members usually develop their own expansion plans and explore opportunities for increased power supply economies with other member and non-member utilities.

The Federal Power Commission has over 2,000 rate schedules on file which reflect various degrees of coordination achieved through interchange arrangements. In addition, many coordinating arrangements have been developed by publicly owned systems and cooperatives which are not subject to FPC jurisdiction and, therefore, have not been filed with this Commission. Numerous types of coordination are reflected in these arrangements which generally have enabled the electric utility systems to achieve greater reliability and lower cost of service than could have been achieved without interconnection and coordination.

It is not feasible to describe in this report all of the various interconnection agreements. However, to provide some indication of the various types of coordination arrangements being utilized and the various degrees of coordination that have been achieved through such arrangements, some of the major coordinating techniques are described below.

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[10] Interconnected Systems Group (ISG) was a voluntary association of electric utilities which began in 1928 and grew to encompass the geographic regions now represented by the following four Operating Areas: East Central Systems, Southeast Region, North Central Region, and South Central Systems.

Staggered Construction of Generating Capacity

Staggered construction is a technique which involves construction of excess capacity by one utility for the use of one or more other utilities with the supplier-buyer arrangement being reversed or modified with each succeeding unit. Several variations of this practice are widely used. Sometimes adjacent systems informally coordinate their capacity additions over a period of several years so that the total installed capacity reserve approximates the amount required by the entire geographic area. Each individual system's reserve in percent of peak-hour load may vary widely from year to year, but the total peak-hour reserves for the group are maintained at approximately a constant level.

A refinement of this coordinating technique includes short-term capacity transactions which permit a system to install a larger unit than its own immediate needs require and to sell firm capacity to neighboring systems for one or more years. Later this utility purchases firm capacity from neighboring systems for a period of time and then repeats the cycle by installing an even larger generating unit. This arrangement has found general acceptance by some power pools and other coordinating groups since each member can achieve benefits from economy of scale and maintain most economically the installed capacity reserves required by the coordinating group.

Another form of staggered construction which has gained widespread acceptance in recent years is the unit-sale concept. This entails arrangements whereby a system installs a larger unit than it otherwise normally would, and sells a specified amount of excess capacity from that unit to one or more neighboring systems. The purchaser's entitlement is limited to the availability of capacity from the specific unit. In the event of an outage of such unit, the buyer is not entitled to any portion of the supplier's other capacity resources. Rates for unit sale transactions usually reflect actual capacity and energy costs from the specific unit involved.

Seasonal Capacity Exchanges

Seasonal capacity exchanges can usually be made when the annual peak loads of two utilities, areas, or regions occur in different seasons of the year. However, individual systems within the same power pool having annual peak demands which occur in different months do not normally participate in seasonal capacity exchanges because, in a pool, savings from intrapool diversity are automatically achieved by the decreased total installed reserve requirements resulting from the pool operation.

Seasonal capacity exchanges may be highly significant on an inter-pool, inter-area, or interregional basis. An example is the arrangement between the Tennessee Valley Authority in the Southeast Region and the South Central Electric Companies (SCEC) [11] in the South Central Region. SCEC and TVA entered into an agreement in 1968, for the exchange of 1,500 megawatts of surplus capacity. The SCEC systems have estimated a total saving of $100 million in capital investment from a reduction in generating capacity installations, as a result of the agreement. In addition to seasonal diversity exchanges, the two parties participate in short-term firm power exchanges, emergency service, and economy energy transactions.

Joint Enterprises

Although jointly owned plants date back to before 1920, joint ownership did not reach significant proportions until after World War II. For the early jointly owned plants, the owners held title to a specified portion of the plant and each owner was entitled to his share of the capacity and output plus any unused capacity of the plant.

An early example is Montaup Electric Company which was organized by three companies,[12] not then affiliated, to build a generating plant and transmission lines to supply a large part of their combined electric power requirements. The Montaup Contract defines the financing and pooling obligations of the companies and provides for payment and charges based on the relative investments of the owners and their relative participation in the capacity and output.

In 1950, Electric Energy, Inc. (EEInc.) was organized by five (now four) sponsoring companies to supply 735 megawatts of firm power and

[11] See table 17.2.

[12] Brockton Edison Company, Fall River Electric Company, Blackstone Valley Electric Company.

150 megawatts of supplemental power to the Atomic Energy Commission at Paducah, Kentucky, pursuant to a 25-year contract. EEInc. installed six steam-electric generating units totaling 1,040 megawatts at its Joppa, Illinois, plant, constructed transmission lines to the Paducah plant, and interconnected with its sponsors.

In 1952, Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), were organized by 15 sponsoring companies to supply the electric energy requirements of the Portsmouth Project of AEC. OVEC constructed a 1,086-megawatt steam-electric plant at Cheshire, Ohio, and IKEC constructed a 1,304-megawatt electric plant at Madison, Indiana. The two plants supply electric power to the Portsmouth Project over four 345-kilovolt transmission lines.

In 1954, the Yankee Atomic Electric Company was formed by ten New England electric utilities to construct a 175 megawatt nuclear plant which went into operation in 1960 at Rowe, Massachusetts. The ten companies which hold stock in Yankee Atomic are entitled to receive and obligated to pay for a percentage of the output in proportion to their stock ownership. Following the success of this project, similar joint enterprises have been formed by more than a dozen New England utilities to construct three additional nuclear power plants.

Another important form of joint enterprise has been the development of Generating and Transmission (G&T) Cooperatives, of which about 25 are now in operation. A G&T Cooperative usually consists of distribution cooperatives which have formed an organization to build one or more generating plants and a transmission system to deliver power to their load centers. The generating and transmission facilities are owned by the G&T Cooperative, and the distribution cooperatives agree to purchase their power requirements from it. Many of these G&T Cooperatives have coordination arrangements of various sorts with privately and publicly owned systems.

A unique arrangement has been worked out between the Ohio Power Company and Buckeye Power Cooperative, a G&T whose membership is made up of all of the REA distributing cooperatives in Ohio. Ohio Power Company constructed a 1,230-megawatt steam-electric plant (two 615-megawatt units) on the Ohio River. The Company sold one of the units to Buckeye Power Cooperative at cost (about $68 million) and agreed to purchase any portion of the output of the unit not needed to meet Buckeye's load requirements. The power is transmitted to the systems of the member cooperatives via the transmission systems of the major investor-owned electric utilities in Ohio. Buckeye obtained financing for the unit through the private money markets, rather than through REA.

The Mount Tom Generating Plant, which was placed in commercial operation in 1960 by the Holyoke Water Power Company, is an example of a project that was made possible by long-term unit sales. All of the output of this 137.5 megawatt single unit plant in excess of Holyoke's needs was committed to two larger neighboring companies, New England Electric System and Western Massachusetts Electric Company. Sales are on a declining schedule until 1971, after which time 83.5 megawatts will be available to the purchasing companies and 54 megawatts will be retained by Holyoke.

Substantive changes have been and are taking place in the number and character of jointly sponsored generating plants. The scarcity of acceptable plant sites, the need to make best use of limited land resources, the availability of turbine-generator units in large sizes, and the total cost and complexity of such units are factors which have encouraged groups of utilities to share in their development, output, and risks. Most joint ownership arrangements are among utilities within the same power pool or planning organization, but there are a few exceptions. For example, New York State Electric and Gas Company, a member of the New York Power Pool, and Pennsylvania Electric Company, a subsidiary of General Public Utilities Corporation which is a member of the PJM Power Pool, have equal ownership in the 1,280 megawatt Homer City mine-mouth generating station. Two 640-megawatt units were installed in 1969. Pennsylvania Electric also joined Cleveland Electric Illuminating Company, a member of the CAPCO Power Pool, to construct the 422-megawatt Kinzua pumped storage project on the Allegheny River in Pennsylvania.

A unique joint enterprise is the Pacific Northwest-Southwest Intertie consisting of 500-kilovolt ac and 800-kilovolt dc transmission facilities. This project is a cooperative undertaking,

bringing together the largest Federal hydroelectric system in the United States, the largest municipal system, and the larger private systems in the West Region. The Intertie provides for the coordinated operation of the utility systems in this 11-state area for reliability and efficient utilization of generating capacity.

Joint Enterprises by Formal Power Pools

A recent development of great significance is the increasing use of joint ownership of facilities by members of formal power pools. Approximately 27,600 megawatts of generating capacity going into service between 1968 and 1975 are owned jointly by members of formal power pools; but more importantly, several of these power pools have adopted procedures to utilize joint enterprises on a continuing basis in the future.

Joint ownership of transmission systems is less widespread than jointly owned generation because most electric utilities prefer to own all transmission facilities within their own service area. Another factor inhibiting joint sponsorship of transmission is the difficulty of allocating the cost of bulk transmission systems among its several almost inseparable functions. The magnitude of this problem varies from pool to pool, depending on the number of members, the relative size of members, and degree of coordination being achieved. Since reliability considerations are requiring more and higher capacity transmission facilities, some individual pool members are being burdened with disparate investment in inter- and intra-pool lines. Therefore, some power pools are beginning to explore and develop techniques for joint sponsorship of bulk transmission along with joint ownership of generating plants.

Every member of a power pool—even a fully coordinated one—has its own unique combination of capacity resources reflecting a specific mix of base load, semi-peaking, and peaking units, often supplemented by power imported from outside its service area. Each member, therefore, relies upon the pool's bulk transmission system in different degrees for emergency support, power interchanges, access to large units, economic dispatch, and delivery of power to load centers. As yet, there is no consensus concerning the proper formula for allocating the cost of a transmission system among its different functions. Nevertheless, members of a few power pools have been able to proceed with joint sponsorship of transmission by limiting considerations to only two functions—reliability and power delivery—and by agreeing to arbitrary allocations of costs between these two functions.

Substantial joint enterprises are being sponsored by the participants of several power pools, including PJM, CAPCO, Pacific Northwest Coordination Group, New England, and CCD. The techniques being utilized by a few of these pools are described below to provide some indication of the degree to which joint sponsorship of generation and transmission facilities is gaining increased acceptance and is accelerating the trend toward more fully coordinated power pools and regional groups.

The PJM Power Pool

PJM participants have sponsored joint projects that provide unique opportunities for taking advantage of low fuel costs and economies of size which could not be realized by a single company. The Keystone and Conemaugh minemouth generating plants, with two 810-megawatt units at each station, are jointly owned by groups of companies which participate in the PJM Pool. The Keystone Station was completed in July 1968. The Conemaugh units were placed in commercial operation in 1970 and 1971. Four additional jointly owned units of over 1,000 megawatts each are under construction.

An extensive 500-kilovolt transmission system, owned by ten participants, was constructed to move power from generating stations to load centers and to provide high capacity tie-lines. The total costs of all the 500-kilovolt lines and substations have been divided into an inter-area tie function and a generation delivery function. The annual cost of the inter-area tie function is allocated among all PJM systems in proportion to size as measured by peak loads. The generation delivery function is allocated to plant owners in proportion to ownership in the combined capacity of the stations. A large scale digital computer and data transmission system, a shared cost facility to schedule and monitor PJM bulk power facilities, is an integral part of PJM's coordinated operation.

CAPCO Power Pool

The genesis of the CAPCO Power Pool was the Central Area Power Coordination Group, formed in December 1964, as an informal planning organization. Under the principles of this planning organization, which embodied no commitments for sharing new generating capacity or allocating reserve requirements, the individual companies were planning to install units of approximately 200 megawatts capacity. In September 1967, the five members of CAPCO [13] signed a Memorandum of Understanding which established a power pool and set forth in detail the obligations of each party. By jointly planning and sponsoring bulk power facilities to supply the growing loads of the entire pool, the members found it feasible to install three 625-megawatt fossil-fueled units, two 860-megawatt nuclear units, and several hundred miles of 345-kilovolt transmission lines for their mutual benefit. Studies are continuing for the installation of additional large scale generation and EHV transmission in accordance with the concept of single system planning.

One unique feature of the pool relates to the installed reserve requirements of each member. Minimum reserves in percent of peak-hour load are not established nor are such reserves equalized. A computer program is utilized to allocate the amount of new generation to be owned by each member so that the dependence on the power pool, as measured by loss-of-load probability studies, is the same for all members. The reserve requirement of each member is related to the size and performance of its capacity resources and load characteristics.

New England Power Pool

Some of the electric utilities in New England have a history of coordinated operation dating back to the early 1920's. More recently, coordination has included staggered construction of large generating units (implemented by short-term sales of excess capacity from new units), extensive economy energy transactions, and the use of intervening transmission. By 1966 more than 5,000 megawatts of generating capacity had been installed or scheduled on the basis of joint ownership and unit participation arrangements.

[13] Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and Toledo Edison Company.

With this background of cooperation and joint planning, the nine largest utilities in New England set out in 1967 to sponsor the formation of a New England power pool (NEPOOL) with the following objectives:

1. To attain for New England maximum practicable economy consistent with proper standards of reliability, in the generation and transmission of bulk power through joint planning, central dispatching, coordinated operation and maintenance of generation and transmission facilities.
2. To provide for equitable sharing of the resulting benefits and costs.
3. To provide a means for more effective coordination with other power pools.

The sponsors of NEPOOL, recognizing at the outset that the development of such a far-reaching pooling agreement would be time-consuming, formed an Interim Operations Committee and Interim Planning Committee [14] so that technical planning and implementation of the power pool could proceed concurrently with the development of an organizational structure. Consequently, coordinated area-wide planning has been in effect since 1967 and a computerized dispatch center has been installed to direct the minute-by-minute operation of the bulk transmission and generation system.

By April 1970, representatives of both publicly and privately owned electric utilities, who had been meeting regularly as a working committee since June 1969, reached an understanding on general principles for a broad power pool agreement covering: (1) a pro-rata allocation of installed generating reserves to each participant; (2) a costing technique to spread the costs of a pool-supported transmission system among the participants; and (3) a basis upon which each participant can choose to secure its power supply for load growth from new units being installed in New England. There is recog-

[14] These committees became the Operations Committee and the Planning Committee on June 1, 1970. Members of the Planning Committee include the nine sponsoring companies shown in table 17.2 in addition to Braintree Municipal Light Board, which also represents four other municipal systems having generation in excess of 25 MW (Burlington, Holyoke, Taunton, and Wallingford). Fitchburg Gas and Electric Company represents Bangor Hydro-Electric Company, Maine Public Service Company, and Newport Electric Company.

nition that different types of generating units may affect the distribution of capacity obligations, but it is agreed that the maximum adjustment is to be limited to 2 percent of the prorata norm. Negotiations are continuing with the expectation that the comprehensive pooling agreement will become effective during 1971.

Small Systems

For the purpose of providing a statistical frame of reference, small electric systems were defined in the 1964 National Power Survey as those having annual peak-hour demands of less than 25 megawatts. By this definition there were 3,190 small systems in 1962, of which 899 generated all or part of their requirements and 2,291 purchased their entire requirements. By 1968 the total number of small systems decreased to 2,842, a reduction of 348, principally as the result of acquisitions and mergers. More than 800 of the remaining small systems owned generating facilities, and 243 were electrically isolated from major transmission networks.

The total cost of generation at the bus bar for the sizes of plants usually installed by small systems is relatively high because such plants cost more per kilowatt to build, burn more fuel per kilowatt-hour, and cost more per kilowatthour to operate. The ability to take full advantage of modern generation and transmission technology is often limited to the larger systems. Only 31 systems with generating capacity of less than 500 megawatts are members of formal power pools.

Since the cost gap between small scale and large scale generation and transmission has been progressively widened by technological improvement, most of the smaller electric systems which generate the bulk of their electric requirements are at a relatively greater economic disadvantage than they were during the 1950's and the early 1960's. Benefits from coordinated planning are being realized by some of these smaller systems through joint ownership, or entitlements in large, more efficient generating units sized to meet area needs, and through associate or affiliate membership in regional councils. Systems which serve their growing needs by power purchases receive reliability and economic benefits when their power suppliers participate in areawide and regional coordination. Direct or indirect participation by smaller generating systems in the benefits and responsibilities of coordinated planning and operation is fundamental if the most efficient use is to be made of our resources. However, when their supplier, alone or in cooperation with other systems, can install large-scale generation, benefits of the larger system scale become available to them.

Power-Supply Sources

Many small systems buy all of their power requirements at wholesale, although they have the option to plan, install, and operate bulk power facilities. A heavy concentration of these distribution systems within a specific geographic area increases the chances of economic feasibility for them jointly to plan and construct their own bulk power system, but such endeavors may result in duplication of facilities unless suitable wheeling arrangements can be worked out with neighboring, and generally competing, systems. Few conversions are anticipated.

Small systems having generating facilities, but with insufficient capacity to meet their total electric requirements, include: (1) those having only a small amount of generation (often, hydro) which is supplemented with purchases from a neighboring supplier (2) systems which plan gradually to phase themselves out of the generating business but still have one or more units in serviceable condition; and (3) systems that use small units for peak shaving to reduce average purchased power costs. There is a wide variety of bilateral arrangements covering such situations. This type of system will continue to be a part of the overall supply, primarily because it provides an intermediate step in moving to or from full within-system generation.

Some small systems have sufficient generation to meet their own requirements and operate in complete electric isolation, or with interconnection facilities normally open. Others are connected to and operate in parallel with major power networks, under a wide variety of agreements. In recent years, some small systems have been able to negotiate lower reserve requirements through coordination of their operations with neighboring systems, and a few have gained access to large scale generation.

Isolated Systems

At the beginning of 1968, 243 systems were electrically isolated from power supply net-

works. Information on these systems is shown in table 17.7. Approximately 82½ percent of the total generating capacity of the isolated systems was located in eight States.

Isolated systems typically experience relatively high power supply costs and inferior bulk power reliability. About 75 percent of the isolated systems in 1966 carried reserve capacity greater than 50 percent of their annual system peak demands. On such systems the forced outage of a generating unit may represent loss of such a large portion of on-line capacity that partial or total power failure may result before other units can respond to meet the increased load placed upon them. Also, an isolated system is vulnerable to extended service interruptions if fire, natural disaster, or other catastrophe destroys one or more of its major generating plants.

Under Section 202 (a) of the Federal Power Act, the Federal Power Commission is directed to promote and encourage the voluntary inter-

TABLE 17.7

Isolated Systems [1]

State	No. and Type of Ownership		Installed Capacity kW	Peak Load kW	Energy Generated MWh	No. of Customers
	Public	Private				
Arizona		1		7,370		2,518
California		1	5,055	2,250	7,922	1,366
Colorado	5		29,234	20,305	72,536	7,554
Delaware	1		7,302	5,500	22,013	2,314
Florida	13		614,312	341,985	1,519,568	122,943
Idaho		1	150	16	32	22
Illinois	23		302,421	160,380	703,023	43,952
Indiana	2		38,080	19,800	84,393	2,249
Iowa	13		41,259	19,830	77,341	11,379
Kansas	49		255,896	128,585	419,734	54,204
Louisiana	8		195,311	131,040	434,408	38,226
Maine	1	1	350	1,060	469	855
Maryland	1		16,375	10,620	47,612	3,877
Massachusetts	2	1	105,100	66,260	293,115	25,319
Michigan	4		22,119	12,700	56,717	5,507
Minnesota	11		66,726	34,079	149,907	15,687
Mississippi	3		111,927	59,100	213,607	17,313
Missouri	8		34,806	17,620	65,354	8,802
Nebraska	28		92,787	43,235	171,589	21,498
Nevada	1	3	6,372	5,438	26,823	4,079
New Mexico	2		17,640	9,400	39,013	4,439
New York	2	2	35,311	21,454	102,278	11,485
Ohio	17		517,646	246,288	1,279,043	109,754
Oklahoma	8	1	57,979	39,121	125,267	16,546
Pennsylvania	2		6,483	3,810	16,527	2,466
Rhode Island		1	1,471	610	1,573	536
Texas	18		339,840	116,229	735,070	56,703
Virginia	2		6,161	3,985	13,300	1,797
Washington	1		250	180	537	63
West Virginia	1			1,516	6,034	955
Wisconsin	2	2	30,750	14,768	70,576	8,743
Wyoming	1			4,290	6,251	188
Subtotal	229	14				
Total	243		2,959,113	1,548,824	6,761,632	603,339

[1] Those systems not interconnected with a network of at least 500 MW of generating capacity, based on data for 1965 through 1967.

connection and coordination of electric systems [15]. It is particularly important for isolated electric systems to analyze the economic and operating benefits of interconnected operations with neighboring systems. Mounting reliability problems, high cost of money, growing problems of finding and retaining good operating personnel, and increasing costs of plant operations are all factors which favor interconnected operations. Staff members of both the Washington and regional offices of the Federal Power Commission may provide advice and other assistance to small systems in analyzing the cost and benefits of interconnected operations and in negotiations of contractual arrangements with neighboring utilities.

Isolated systems can attempt to secure reliable wholesale service at reasonable prices and on fair terms under certain circumstances by order of the Federal Power Commission [16]. The Commission has ordered several interconnections in response to complaints by isolated systems. Such measures, while providing improved reliability and lowered reserves, primarily for the small system, have not eliminated the installation of relatively small generating units which would not be constructed if area-wide planning and coordination were complete.

Interconnected Systems

Approximately 1,200 systems with annual peak hour loads of 500 megawatts or less are electrically connected to major power networks and operate their own generating facilities. Because the relative economic advantage of doubling the size of a unit in the 25-megawatt range, for example, is far greater than in the 250-megawatt range, smaller systems have a strong incentive to maximize the size of their new units. Nevertheless, they may not install large, economic units because the complexity of the required coordination contracts tends to discourage this practice. In recent years, however, there has been a gradual change in the traditional attitudes between large systems and small systems. The accelerated coordination activity throughout the country has in many areas greatly enhanced opportunities for area-wide coordination. As a result, about 10 percent of the systems with annual peak demands of 500 megawatts or less are now participating in coordination arrangements involving reserve sharing, reciprocal emergency assistance, economy exchange, etc.; and the number of systems that receive benefits from large scale generating facilities is increasing.

Small-Scale Power Pooling

Small generating utilities which do not participate in area-wide coordination are under constant economic pressure to improve their bulk power supply situation. A number of these systems have achieved significant reductions in power supply costs by interconnecting with other small systems in similar circumstances. Rapidly increasing loads provide additional incentives for the expansion of these coordinating groups and the formation of new ones. Although such efforts may produce beneficial results for the participants, they usually result in the construction of less than optimum generating facilities, duplication of transmission, and a bulk power supply which, from an area-wide or regional perspective, is fragmented.

Potential Benefits of Full Coordination

Simultaneous outages of major generating plants, delays in placing new generation in service on schedule, fuel shortages, and unforeseen power demands have jeopardized or degraded bulk power supply in some sections of the country. Overall system stability must be protected at all times in spite of these difficulties, so there is need to provide large blocks of economic and reliable generation, and to provide transmission networks capable of transferring large amounts of power from one area to another.

The electric utility industry can achieve full coordination, without altering its pluralistic character, by coordinating the planning, construction, and operating activities of all utility groups in areas with loads of sufficient size to realize all the potential benefits of modern technology, and by strengthening generation and

[15] See footnote 9, page I–17–17.

[16] Section 202 (b) of the Federal Power Act authorizes the Commission, upon application of a state commission or of any person engaged in the transmission for sale of electric energy, to order a public utility to interconnect its facilities with those of the applicant and to sell or exchange energy with the applicant, provided the interconnection does not require the public utility to enlarge its generating facilities, or does not impair its existing services.

transmission facilities as necessary for assuring adequacy and reliability of power supply. Certainly, from both the resource conservation and economy of service viewpoints, coordination among all of the utilities within the respective regions should be a major objective.

Trend to Larger Coordinating Groups

If only technological factors were to be considered, utilities in each region of the United States could be reorganized into a large and more efficient coordinating unit to provide optimum economy consistent with a reliable and adequate nationwide bulk power supply. However, organizational trends within the utility industry are shaped by institutional, social, economic, and political considerations as well as technological factors.

Corporate consolidation is one way by which electric utilities may be regrouped. Mergers were the principal means for achieving rapid system growth until the 1930's. Thereafter, improved reliability and the economic advantages of scale were achieved principally by interconnections and inter-system coordination, although mergers and acquisitions have continued to eliminate some management, administrative, and operating duplications. Interest in enlarging utility system size via the common holding company or by acquisition of major properties was revived during the 1960's. Between 1965 and 1968, more than 20 affiliation programs involving Class A electric utilities were proposed. Northeast Utilities, formed in July 1966 by Connecticut Light & Power Company, The Hartford Electric Light Company, and Western Massachusetts Electric Company, was the first of these new holding companies to achieve operational status. The most ambitious of the proposals involves the formation of a holding company by the five CAPCO pool members (table 17.2) plus Cincinnati Gas & Electric Company; Dayton Power & Light Company; and Union Light, Heat & Power Company. This proposed venture, if successful, would make the new entity the country's largest holding company system in terms of annual revenue and electric load.

Power pools can accomplish somewhat the same result as holding companies by enabling individual utilities to achieve many of the economies and other advantages of a much larger system while still maintaining their own separate identities. The attainment of these objectives requires the same careful coordination of planning and operation performed by the holding company system, but the process is more complicated by separate management of the various parts of the integrated network and the necessity of working through committees. A major advantage is that power pools can more easily be expanded into large, more efficient coordinating units comprising utilities from all industry segments. Several holding company systems have improved their bulk power supply economy through membership and active participation in formal power pools.

As power pools become larger and more effectively coordinated, opportunities for reducing the duplication of various management and engineering functions may continue to encourage the formation of larger utilities through corporate merger and consolidation. Certainly the decision-making process by an area-wide coordinating group would be simplified by a reduction in the number of participating systems. However, the impact on competition, the responsiveness to local area needs by utility management, the treatment of combination electric and gas utilities, and the possible further concentration of economic power will provide provocative issues in testing whether the broad public interest would best be served by the formation of large holding company systems.

Prospects for Increased Coordination

Despite the remarkable increase in the number and kinds of coordinated utility groups, centralized pool-wide dispatch has received only limited acceptance. Through the 1960–1968 period, there were approximately 150 separate control areas of which only five were centrally dispatched power pools. Under interconnected operation, each control area must have automatically regulated generation to absorb area load changes, maintain scheduled interchanges with neighboring areas, provide assistance to other control areas in the interconnected system when they have difficulty matching load with generation, and furnish a proportionate share of system frequency control. The technique for automatically accomplishing these functions is generally referred to as load, frequency, and tie-line bias control.

The continued increase in the extent of interconnections and the complexity of networks have increased the need for more sophisticated control of interconnected systems to improve reliability and to maximize economic advantages. Accelerated coordination activity will probably give added impetus to on-line dispatching over broad geographic areas and to the eventual elimination of multiple control areas within power pools.

Centralized dispatch and continuous digital computer control of generation were initiated by the Michigan Power Pool in the spring of 1969, by New England Power Pool (NEPOOL-NEPEX) in June 1970, and is scheduled for operation by the New York Power Pool by the end of 1971. These three installations will replace 16 separate control areas. The PJM Power Pool, which has had a single control area for many years, converted its centralized dispatch of generation to continuous digital computer control during 1969. Successful experience with on-line computers for central dispatch by these four power pools should encourage similar installations for improved system reliability and operating efficiency by other power pools throughout the nation.

To some degree, the formation of a large number of coordinating organizations, each having limited functions and objectives, has diffused the coordinating process. It is not unusual for utilities in some parts of the nation to be members of four or five different coordinating groups, each dealing separately with such matters as interconnected operations, planning, reserve sharing, adequacy of power supply, and prevention of cascading power failures. Existing organizational mechanisms will predominate during the immediate future, but unprecedented challenges for improving reliability while retaining or enhancing the quality of the environment will increase the need to optimize capital investments and should encourage utilities to intensify the development of fewer but more comprehensive coordinating mechanisms.

Although it is difficult to forecast the future pattern of coordination, it appears likely that industry-wide efforts to consolidate and expand utility groups to optimize the use of improved technology and intersystem coordination will continue during the next decade. Recent progress in self-organization by the electric utility industry is oriented toward regional coordination. The following discussion gives some indication of the future coordination patterns that the Commission's staff believes may develop within each region of the country.

Northeast Region

Evolution of inter-system coordination in the Northeast Region has resulted in the creation of three large power pools—NEPOOL, NYPP, and PJM; and two regional councils—NPCC and MAAC.

The Northeast Regional Advisory Committee (NERAC) in its report to the Federal Power Commission [17] anticipated that the factors influencing optimum pool size and the relationship among coordinating organizations in the Northeast Region would continue to be reviewed and evaluated as improvements become available in all aspects of power supply technology and methodology. Accordingly, in April 1969, NPCC approved the development and implementation of a program for coordination of regional planning covering economic relationships among the New York and New England pools, and the Ontario Hydro system, including the development of a long-range expansion pattern for generation and transmission facilities.

Additional actions which appear as possibilities for the future are:

1. Extension of joint planning—to include all systems with significant generation in the region.
2. Expansion of NPCC to include the Maritime Power Pool—New Brunswick Electric Power Commission, Nova Scotia Power Commission, and Nova Scotia Light & Power Company.
3. Consolidation of the New York and New England pools into a single fully coordinated planning and operating organization.

Southeast Region

Two utilities—Tennessee Valley Authority (TVA) and the Southern Company System—own more than 53 percent of the Southeast Region's generating capacity. The Carolinas-Vir-

[17] See Part II of this Report.

ginia Power Pool (CARVA)[18], which consists of four investor-owned utilities, accounts for another 25 percent of the region's generating capacity. The remaining generating capacity, exclusive of electrically isolated systems, is owned by the five members of the Florida Operating Committee (16.75%) and by seven electric systems from all segments of the industry (4.4%).

The vehicle for inter-system coordination in Peninsular Florida is the Florida Operating Committee which is concerned primarily with coordination of day-to-day operating practices, spinning reserve, scheduled maintenance, and load shedding procedures. The utilities which constitute this Committee informally participate in coordinated planning studies, but these activities do not provide the economic benefits potentially possible from single system planning and operation.

The recently organized Southeastern Electric Reliability Council (SERC) can be expected to undertake the examination of problems relating to bulk power supply and to identify actions which may be appropriate to provide sub-regions with adequate internal and external power transfer capability.

Other actions which appear likely during the next decade include:

1. Extension of joint planning within the Southern Company, Virginia-Carolinas, and Florida Peninsular sub-regions, to include all systems with significant generation.
2. Joint studies to test the feasibility of a single power pool encompassing the Southern Company system and the Florida utilities.
3. Expanding the functions of SERC for achieving optimum reliability and economy of bulk power supply on a region-wide basis.

East Central Region

Utilities in the East Central Region have established six formal power pools[19] whose members own approximately 90 percent of the generating capacity in the region. The region's one regional council—the East Central Area Reliability Coordination Agreement (ECAR)—directly represents more than 95 percent of the total generating capacity in the region.

Several power pools in the region are too small by themselves to take full advantage of the large generating units that are available, but this situation is mitigated to some extent by close inter-pool coordination and by joint planning of facilities when specific opportunities are identified. Recent activities in the area suggest a trend toward larger but fewer power pools. Several ownership consolidations and pool realignments are under active consideration.

ECAR is developing criteria for installed generating reserve for ECAR and each member system. It is likely that such criteria will be adopted by the Council during 1971 at which time member systems should have greater flexibility to plan for the optimum combination of bulk power facilities within major geographic areas.

Better planning coordination usually is accomplished by greater operating coordination. Allegheny Power System and American Electric Power Company, the two holding company power pools in the region, have had centralized dispatching and pool-wide control areas for many years. In 1969, members of the Michigan Power Pool initiated operation of a computerized dispatch center for continuous on-line control of their combined bulk power facilities. Nevertheless, 16 separate control areas remain in the region. A teletype system has been installed which connects the ECAR executive offices with the control center of each member system. As joint planning and joint ownership of generation continue to receive greater acceptance, it is likely that the control areas maintained by individual systems will be consolidated within major geographic areas or on a pool-wide basis.

West Central Region

Variations in load density and in the nature of electric systems within the West Central Region have produced differences in coordination patterns. In the eastern portion of the region, 95 percent of the generating capacity within the geographic boundaries of the Mid-America Interconnected Network (MAIN) is owned by

[18] The CARVA Pool was terminated October 20, 1970, but annual payments for authorized pool transmission facilities will continue until 1979 and the parties will adhere to the principle of equalized reserves through April 30, 1973.

[19] See Table 17.2.

MAIN members but only 35 percent of the capacity is owned by members of formal power pools. Problems of reliability and adequacy of bulk power supply are handled by MAIN, which is continuing to develop coordination arrangements to achieve increasing economies in bulk power supply through joint scheduling of capacity, coordinated use of transmission facilities, and economic dispatch of generation. As advancing technology provides additional incentive for joint planning and for sharing equitably the responsibilities of the coordinated effort, power pools should gain wider acceptance and thereby represent a greater portion of generating capacity in the area than the present 35 percent.

Intersystem coordination in the remainder of the West Central Region is markedly different. Three formal power pools, which have been established to improve the power supply efficiency of their members, represent more than 75 percent of the generating capacity in the western portion of the region. These power pools are unique in the sense that they are comprised of relatively small systems from all segments of the industry. Upper Mississippi Valley Power Pool (UMVPP) membership consists of seven investor-owned systems and six REA cooperatives. Iowa Pool contains five investor-owned systems and one REA cooperative. Missouri Basin Systems Group (MBSG) is comprised entirely of publicly owned and cooperative systems.

Intersystem coordination arrangements among members of Mid-Continent Area Power Planners (MAPP), the informal planning group which encompasses most of the western portion of the region [20], have developed opportunities which foreshadow a restructuring of pooling organizations in this area. The MAPP Executive Committee is developing an orderly procedure for combining the Iowa Power Pool, UMVPP, and Nebraska public power systems into a single power pool.

Mid-Continent Area Reliability Coordination Agreement (MARCA), a council organization dedicated to the improvement of reliability and adequacy of power supply in the area, has adopted planning and operating criteria and instituted procedures for studying the bulk power network. Members of MARCA own approximately three-fourths of the generating capacity within MARCA's geographic boundaries. Although bulk power facilities of MBSG are in close proximity and interconnected with MAPP members at many points, divergent views on members' responsibilities and marketing policies have impeded efforts to proceed with joint planning of generation and transmission facilities on an area-wide basis. Participation in MARCA by MBSG members may provide a forum for the resolution of these differences.

[20] See Figure 17.2.

South Central Region

Evolution of coordinated planning and development among individual systems in the South Central Region has been within sub-areas leading toward the creation of two major, but separate, power networks. One of these, which is located in Texas, does not operate interconnected with the vast power grid which interconnects 95 percent of the generation in the contiguous United States.

The only coordinating group in the South Central Region organized on a region-wide basis is primarily concerned with system operating matters. This group, the South Central Systems of NAPSIC, embraces investor-owned, Federal, State, G&T cooperatives, and municipal utilities. Through it, uniform practices for interconnected operation within the South Central Region have been achieved and are under periodic review.

That portion of the South Central Region located in Texas contains about 45 percent of the region's total generating capacity. Here, the primary thrust of inter-system coordination is directed to assuring adequacy and reliability of bulk power supply through the Electric Reliability Council of Texas (ERCOT). Increased inter-system coordination during the 1971–1990 period can be expected to result in the increased use of large generating units and the construction of more extensive EHV transmission.

Coordinated planning and development in the other portion of the South Central Region is sponsored by the Southwest Power Pool (SPP), which was reconstituted in December 1969 as a broad-based reliability council. The three formal power pools in the SPP area (MOKAN, SCEC, and Middle South Utilities System) own 80 percent of the total generating

capacity within the boundaries of SPP. Financial benefits potentially available from technological improvements have served to accelerate the degree and scope of coordinated planning and operations among pool members.

Although a few non-pool members have been able to install units as large as 100 megawatts through bilateral arrangements with neighboring utilities, the gap in bulk power supply economy between pool members and non-pool members is widening at an increasing rate. Consequently, some of the smaller utilities that do not participate in power pools are attempting to reduce their power supply costs by interconnecting and coordinating with other small systems in similar circumstances. These efforts to form small coordinating groups may produce some beneficial results for the participants, but only by the construction of generation and transmission facilities which are less efficient than could be installed through area-wide coordination. As a result of modifying membership qualifications in 1969, SPP now provides systems of all sizes with a useful forum where opportunities for extensive planning and operating coordination can be explored. Initial efforts may well be directed toward coordinated construction and joint use of transmission facilities to avoid the construction of duplicating lines. Agreements between pool members and non-pool members regarding coordination of transmission facilities may lead to exploring the financial benefits possible from coordinating generation expansion programs.

The Texas Interconnected System (TIS) portion of the South Central Region can be interconnected to the interstate power network only by the construction of multiple EHV facilities. Consideration of such ties should include analyses of the advantages and disadvantages of both ac and dc facilities. With synchronous operation, such interconnections would need to be capable of handling most of the instantaneous power flow which would occur during the loss of a major unit or plant on the Texas systems since the size of TIS is a small percentage of the national grid. Potential savings from such interconnections include improved reliability during instantaneous emergencies, reduction in spinning reserve requirements, savings in capacity reserves, mutual assistance during fuel shortages and heat storms, economy energy interchanges, possible seasonal diversity exchanges, assistance on maintenance outage schedules, and firm power arrangements. Analyses should be initiated which could lead to orderly planning, design, and construction of these interregional ties.

West Region

About one-third of the land in the 48 contiguous states lies within the boundaries of the West Region. More than 60 percent of the electric energy generated in the region is consumed in load centers along the Pacific Coast. As of January 1, 1968, 56.3 percent of the generating capacity was installed by investor-owned systems, 23.4 percent by public non-federal systems, and 20.3 percent by Federal systems. Most utility groups in the region are informally organized, sub-regional in scope, and primarily concerned with coordinating operating practices. Western Systems Coordinating Council (WSCC), a region-wide council formed in August 1967, is concerned principally with the improvement of bulk power adequacy and reliability on a regional scale.

Coordinated planning to assure more economic operations is emerging as a significant activity among groups of utilities in the West Region. As in other regions of the country, the financial benefits attainable from large generating units is one of the factors. Another important factor is the scarcity of new hydroelectric sites which will limit the expansion of Federal systems to meet the growing loads of publicly owned systems and other preference customers [21]. Consequently, many publicly owned and rural cooperative systems are participating in joint planning with neighboring utilities to sponsor the installation or share the output of large thermal generating units.

The Pacific Northwest Coordination Agreement (PNCA) was organized in 1961 to coordinate the operation of bulk power facilities and major reservoirs, and to enunciate reserve requirements and other responsibilities of interconnected operation. Members signatory to this agreement include the Bonneville Power Administration and the major investor- and publicly-owned utilities in Oregon, Washington, and

[21] The composition of generating resources in the region is expected to change from 53 percent thermal in 1970 to 75 percent thermal in 1990.

Montana that operate generating facilities. However, The Joint Power Planning Council is the vehicle for coordinated planning in this area. This agency of four investor-owned and 104 publicly- owned utilities has developed a plan to provide the needs for base load and peaking generating facilities through 1990.

The California Power Pool, organized in 1964, provides the basic framework for coordinating the planning, constructing, and operating of the electric systems of the member companies. It establishes certain minimum reserve margin requirements for capacity and energy resources and for spinning reserves. It also provides for six specific services for sharing reserve margins and other obligations for continuous and parallel interconnected operation among its three participating systems.

The Pacific Northwest-Southwest Intertie permits utilities in the Pacific Northwest and California to take advantage of seasonal diversities which exist between the northern and southern portions of the region. It makes possible better use of hydro power during the summer through sales to California. Correspondingly, the predominantly hydro Northwest is able to call upon steam-electric power in California during other seasons when low water normally occurs. However, there is no region-wide organization to sponsor studies of additional economic opportunities on a continuing basis.

Although WSCC is making significant progress in developing programs and operating procedures to enhance the benefits of interconnected operation, and in finding solutions to reliability problems, the Council has no responsibility to assure the timely construction of needed facilities. Additional high-capacity tie lines would make possible more stable operation and increase the power transfer capability between certain sub-regions. During the next few years, WSCC might well expand its functions to identify needed facilities and to assure their timely construction. Also, it is probable that area-wide coordinating organizations will be strengthened to plan the installation of optimum bulk power facilities and to distribute equitably the burdens and responsibilities of the coordinated efforts.

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CHAPTER 18

POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION THROUGH 1990

Introduction

Since publication of the Federal Power Commission's National Power Survey in December 1964, the major emphasis in power system planning has shifted from economy of interconnected and coordinated operation of power systems to reliability and adequacy of electric service in a broad framework of environmental protection. This shift in emphasis has in no way limited the urgency of meeting customer demands for power in the most practical manner, but it is significantly influencing the type, location, and design of all types of power facilities. This chapter outlines, in broad terms, the directions in which the industry is expected to move during the ensuing two decades. The forecasts are not to be construed as precise plans, but rather as general targets, with adequate room for adjustment, to meet changing conditions. For example, the Commission believes that before 1990 the technology of direct-current transmission will have advanced to the point that dc systems will be installed in lieu of, or in addition to, some of the ac lines projected by the Regional Advisory Committees. If this change occurs, it will not alter the general goals set forth herein, but will merely provide a better means of meeting those goals. Similar changes are apt to occur in other fields, but they too should fall within the supply-demand framework of the forecasts.

In 1967 and 1968, the six Regional Advisory Committees developed general plans for generation and transmission to meet the Nation's needs to 1990. Starting with the products of the Regional Advisory Committees, the Commission staff adjusted the Committee forecasts to reflect more recent data, and developed projections set forth for meeting future generation and transmission requirements.

Possible Patterns of Generation to 1990

Total Generating Capacity

Generation, peak demand and reserve in percent of peak for 1970 for the contiguous United States and possible patterns for 1980 and 1990 are indicated in table 18.1. Similar data are shown graphically on Figures 4.1 and 4.2.

The most significant change anticipated in the composition of future generating capacity is the increasing reliance on nuclear capacity. This is expected to increase from less than two percent of total capacity in 1970 to nearly 40 percent in 1990. The 475,000 megawatts of nuclear capacity projected for 1990 will include a growing number of breeder reactors. However, the actual breeder capacity will depend upon the U.S. breeder development timetable, presently aimed at commercial availability by the mid-1980s.

Fossil-fueled steam-electric power plants have, in recent years, accounted for more than 75 percent of total generating capacity and have produced more than 80 percent of the electric energy. While the percentage of fossil capacity will decline, the amount of fossil-fueled steam-electric capacity will more than double in the period to 1990.

The percentage of conventional hydroelectric capacity of the total power supply is expected to decrease, primarily because of the limited number of remaining sites suitable for economic development. On the other hand, pumped storage hydroelectric capacity is expected to increase from less than 4,000 megawatts in 1970 to about 70,000 megawatts in 1990. Many areas of the country have numerous potential pumped-storage sites that can be developed at relatively low cost. This, combined with the anticipated increase in availability of low incremental cost nu-

TABLE 18.1

Generating Capacity by Types of Prime Mover, Peak Demands and Reserves

Capacity	1970 [1]		1980		1990	
	MW	Percent	MW	Percent	MW	Percent
Conventional Hydro	51,600	15.2	68,000	10.4	82,000	6.5
Pumped Storage Hydro	3,600	1.1	27,000	4.0	70,000	5.6
IC and Gas Turbines	19,200	5.7	40,000	6.0	75,000	5.9
Fossil Steam	259,100	76.1	390,000	58.6	558,000	44.3
Nuclear	6,500	1.9	140,000	21.0	475,000	37.7
Total	340,000	100.0	665,000	100.0	1,260,000	100.0
Peak Demand	275,700	....	555,000	....	1,050,000	....
Indicated Reserves	64,300	....	110,000	....	210,000	....
Reserves in Percent of Peak	23	....	20	....	20	....

[1] Year-end capacity is shown, some of which was installed after the date of peak demand. Therefore, actual reserves were somewhat less than indicated.

clear energy for pumping, is expected to lead to increasing use of pumped storage as a source of peaking capacity.

Reciprocating engines (mostly diesel) and gas turbine generators aggregated 19,200 megawatts in 1970, about six percent of total capacity. Their numbers are expected to increase, with combined capacity amounting to approximately 75,000 megawatts by 1990. As such capacity is installed mainly for peaking and emergency use, it produces only a very small part of the total energy. Nevertheless, it is an important component of the power supply. Gas turbines, particularly because of their low capital cost, short lead time, and ease and speed with which they can be started and loaded automatically, afford a desirable type of peaking and standby (reserve) capacity. Even though diesel prime movers possess similar characteristics for start-up and loading, they are not expected to be available in large enough sizes to represent a large component of peaking capacity.

The present and probable future locations of major load centers (figure 18.1) were important factors in developing the 1980 and 1990 patterns of generating capacity. The generalized locations of major centers of generation, by types of prime mover, for the years 1970, 1980, and 1990 are shown on figures 18.2, 18.3 and 18.4.

The amounts of generating capacity by types listed in table 18.1 represent the sum of the capacity totals for each of the six regions into which the contiguous United States was divided. Similarly, the magnitudes of annual peak demand and required reserves are the sums of the regional demands and reserves.

In considering future needs for new generating capacity, it is necessary to allow for retirements of existing capacity. To determine the probable magnitude of retirements, a study was made of the age of the 1970 generating equipment by type of prime mover. The results of this study are shown in table 18.2.

Conventional hydroelectric projects have service lives up to 100 years, although most items of equipment are replaced at least once during the service life. In the study of new capacity needs during the next two decades, it was assumed that hydroelectric capacity retirements would be replaced in kind. Retirements of pumped storage hydro, gas turbine, internal combustion, and nuclear installations during this period will not be significant in terms of total capacity. Assuming that fossil-fueled steam-electric capacity will be retired at the end of 35 years of service, retirements will total 24,630 and 60,769 megawatts during the periods 1971–1980 and 1981–1990, respectively. Taking these retirements into account, the needs for new capacity are shown by type of prime mover in table 18.3.

Information in the reports of the Regional Advisory Committees and the report of the Technical Advisory Committee on Generation was supplemented by staff studies to project how the capacity needs in table 18.3 might be met. The details on new conventional and

TABLE 18.2

1970 Generating Capacity by Dates of Installation and Types of Prime Mover—Contiguous United States

[Megawatts]

Date of Installation	Conventional Hydro	Pumped Storage Hydro	Fossil Steam	Nuclear	I.C. and Gas Turbines	Total
1940 & earlier	10,548	24	17,961	0	426	28,959
1941–1950	6,358	11	23,831	0	959	31,159
1951–1960	14,566	59	95,365	493	1,369	111,852
1961–1970	20,128	3,506	121,943	6,007	16,446	168,030
Total Capacity	51,600	3,600	259,100	6,500	19,200	340,000

pumped storage hydroelectric installations are given in chapter 7. For fossil-fueled and nuclear steam-electric capacity, particular attention was given to the unit sizes that may be installed. Unit size has a direct effect on capital costs and economy of generation, and also on the amount of reserve generating capacity required for reliable service. Large sizes have lower unit costs but tend to increase required reserves. In addition to balancing the economy of size with the cost of additional reserves, there are many other factors which must be considered in selecting the optimum unit size for installation at a particular time and place. These include manufacturing limitations, load growth, load concentrations, environmental considerations, and transmission needs.

The maximum sizes of fossil-fueled and nuclear steam-electric units assumed by the Regional Advisory Committees are listed in table 18.4.

The Technical Advisory Committee on Generation projected that 2,000-megawatt fossil-fueled units would be available by 1980 and 3,000-megawatt units by 1990. This Committee also projected that nuclear units would increase in size to 3,000 megawatts. The sizes of units selected for purposes of this report fall generally between the sizes projected by the Regional Technical Committees. The estimated composition of the 1980 and 1990 fossil-fueled steam-electric capacity by unit size is shown in table 18.5.

Because of retirements of small existing units, the number of units operating in 1980 and 1990 will decrease appreciably despite substantial increases in total capacity. For example, the number of operating units is expected to decrease by more than 800 during the 1981–1990 period when a net increase of 168,000 megawatts of capacity is anticipated (229,000 MW of new capacity less retirements of 61,000 MW of existing capacity.)

The projected composition of the 1980 and

TABLE 18.3

New Capacity Needs by Type of Prime Mover

[Megawatts]

Type of Capacity	1971–1980	1981–1990	1971–1990
Conventional hydro	16,000	14,000	30,000
Pumped storage hydro	23,000	43,000	66,000
IC and gas turbines	21,000	35,000	56,000
Fossil steam	156,000	229,000	385,000
Nuclear	134,000	335,000	469,000
Total	350,000	656,000	1,006,000

TABLE 18.4

Maximum Size of Generating Units Anticipated by Regional Advisory Committees

[Megawatts]

Region	1980		1990	
	Fossil	Nuclear	Fossil	Nuclear
Northeast	1,200	1,200	1,500	2,000
East Central	1,300	1,500	2,000	2,500
Southeast	1,200	1,200	1,500	2,000
West Central	800	1,500	1,100	2,000
South Central	1,060	1,060	1,700	1,700
West	1,000	1,200	1,500	2,000

MAJOR ELECTRIC LOAD CENTERS

1970 — 1990

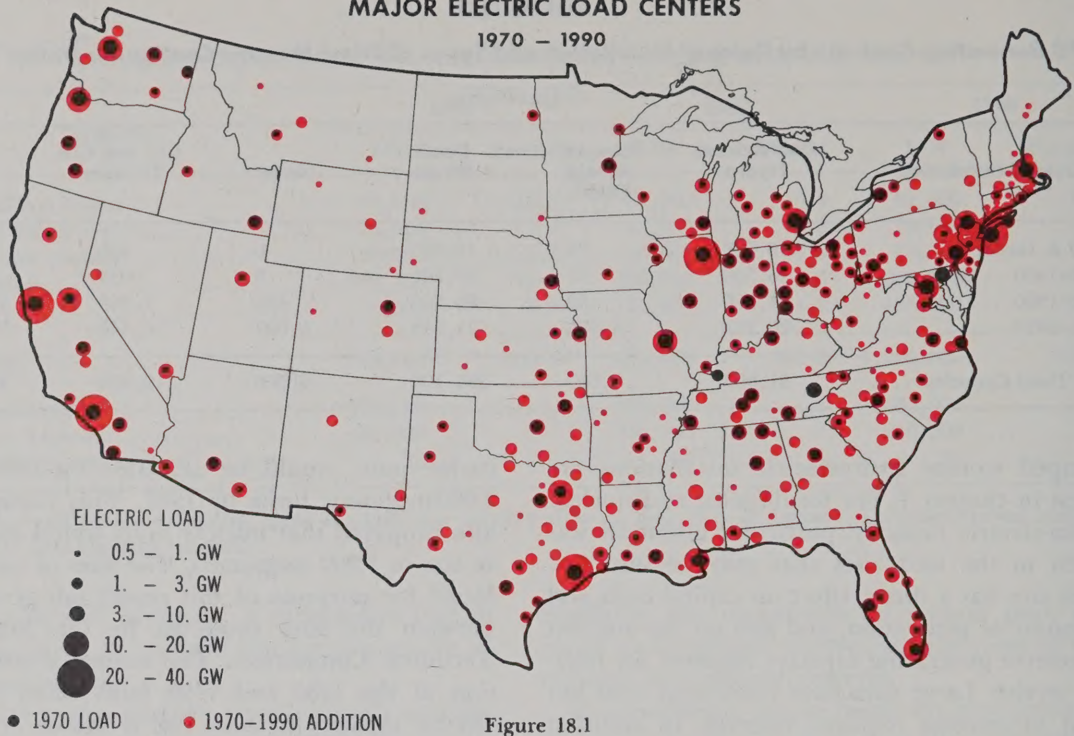

Figure 18.1

GENERATING CENTERS

1970

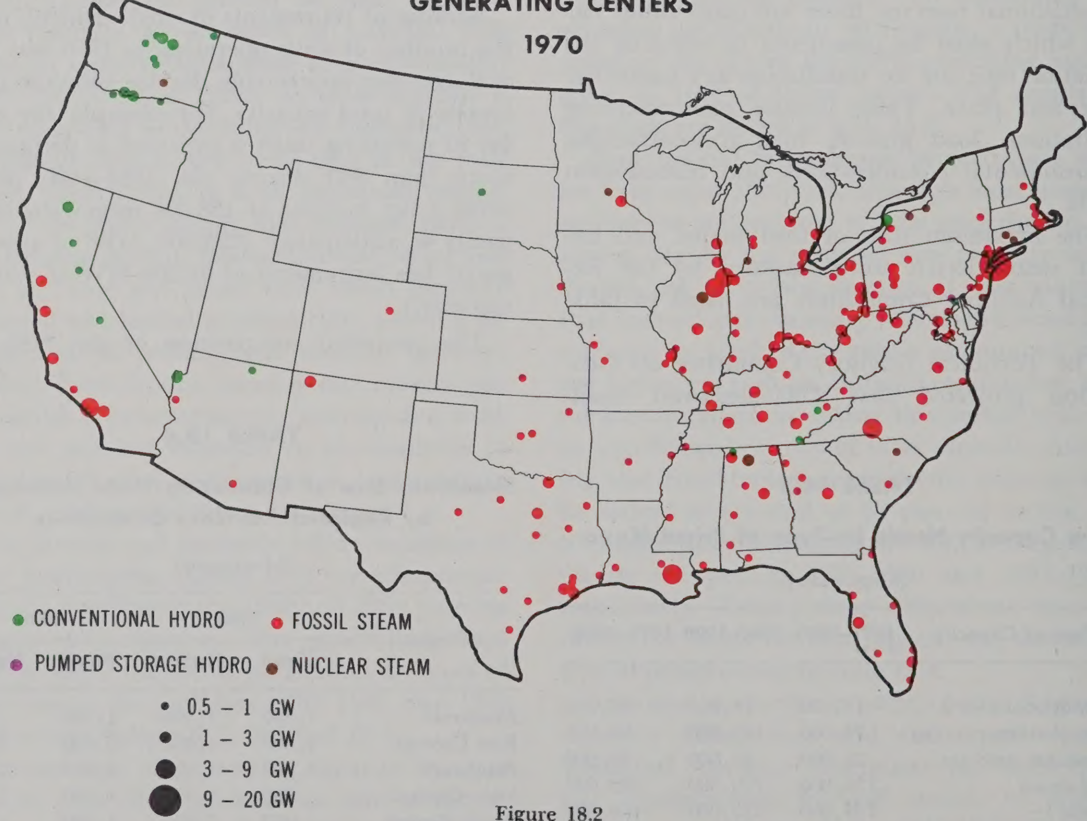

Figure 18.2

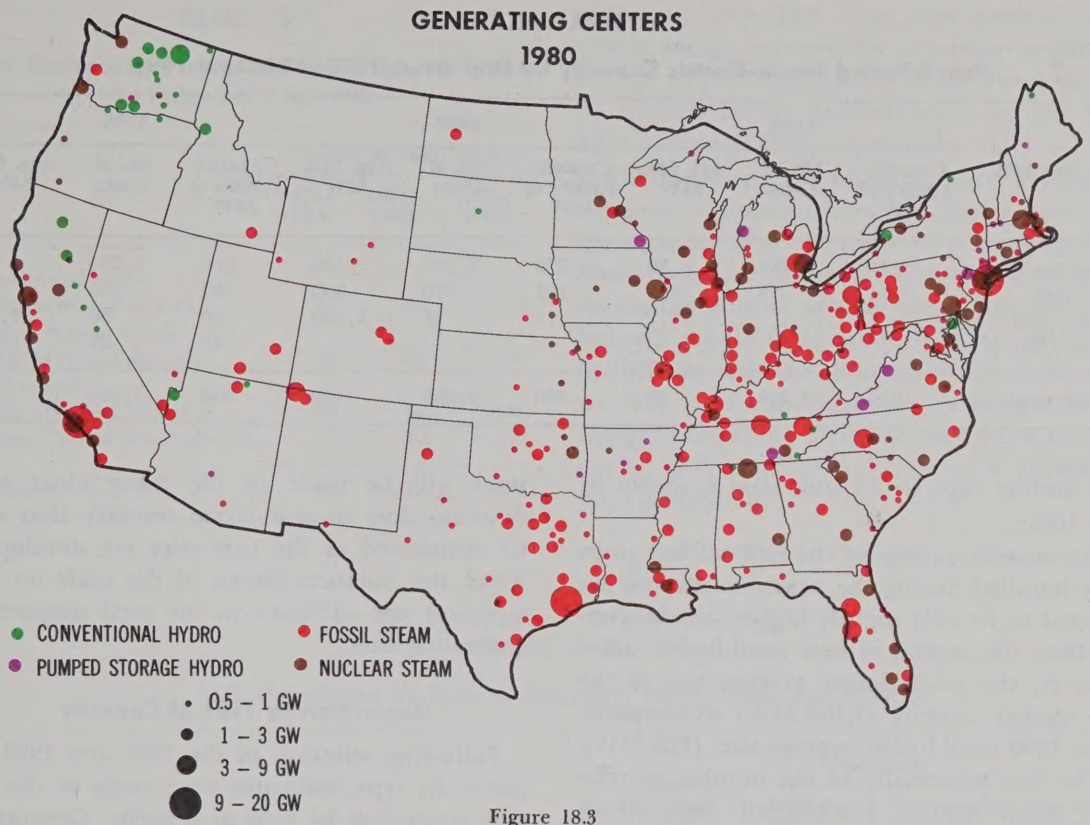

Figure 18.3

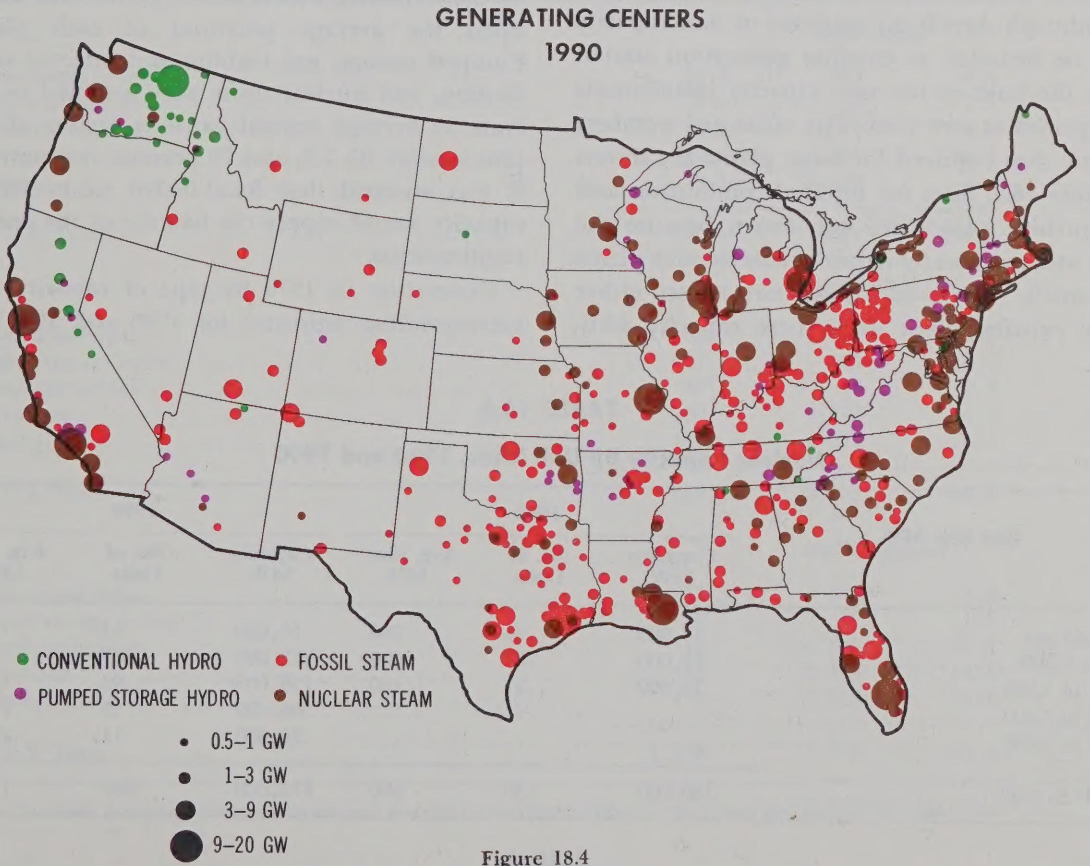

Figure 18.4

TABLE 18.5

Fossil-Fueled Steam-Electric Capacity by Unit Sizes, 1970, 1980 and 1990

Unit Size MW	1970 Capacity 1,000's of MW	1970 No. of Units	1970 Avg. Size MW	1980 Capacity 1,000's of MW	1980 No. of Units	1980 Avg. Size MW	1990 Capacity 1,000's of MW	1990 No. of Units	1990 Avg. Size MW
600 and less......	235	3,265	70	273	2,258	120	262	1,254	210
601 to 1200......	24	33	750	102	120	850	163	185	880
1,201 to 1,800....				15	11	1,360	90	60	1,500
1,801 to 2,400....							43	21	2,050
U.S. total....	259	3,298	80	390	2,389	160	558	1,520	370

1990 nuclear capacity by unit sizes is shown in table 18.6.

The capacity ratings of the new nuclear units to be installed during the next two decades are expected to be only slightly higher, on the average, than the ratings of new fossil-fueled units. However, the much larger average size of the 1990 nuclear capacity (1,160 MW) as compared to the 1990 fossil-fueled average size (370 MW) will be due principally to the number of relatively small existing fossil-fueled units which will still be operating in that year.

Although significant amounts of new capacity will be installed at existing generation station sites, the bulk of the new capacity installations is expected at new sites. The estimated numbers of new sites required for large plants are shown in table 18.7. Sites for internal combustion and gas turbine plants are not shown because the land areas and water requirements for such plants are small. Table 18.7 does not reflect either those existing plant sites where capacity additions will be made or the many older sites (usually close to population centers) that will be abandoned as the new sites are developed. Thus, the numbers shown in the table do not represent net additions to the total number of generating sites.

Generation by Type of Capacity

Following selection of the 1980 and 1990 capacity by type, estimates were made of the energy generation by type of capacity. Generation by conventional hydroelectric plants was based upon the average potential of each plant. Pumped storage, gas turbine and internal combustion, and nuclear units were assumed to operate at average annual capacity factors of approximately 10, 7.5, and 70 percent, respectively. It was assumed that fossil-fueled steam-electric capacity would supply the balance of the energy requirements.

Generation in 1970 by type of capacity and corresponding estimates for 1980 and 1990 are

TABLE 18.6

Nuclear Capacity by Unit Sizes, 1980 and 1990

Unit Size MW	1980 Capacity MW	1980 No. of Units	1980 Avg. Size MW	1990 Capacity MW	1990 No. of Units	1990 Avg. Size MW
600 and less....	13,000	34	380	18,000	43	420
601 to 1,200....	93,000	101	920	223,000	227	980
1,201 to 1,800....	34,000	23	1,480	139,000	95	1,460
1,801 to 2,400....				66,000	32	2,060
2,401 to 3,000....				29,000	11	2,640
U.S. total....	140,000	158	890	475,000	408	1,160

TABLE 18.7

New Generating Plant Sites Required by Types of Plant 1971 to 1990

	Number of Plant Sites		
	1971–1980	1981–1990	1971–1990
Conventional hydro (100 MW and above)	15	25	40
Pumped storage hydro (300 MW and above)	20	35	55
Fossil steam (500 MW and above)	80	60	140
Nuclear (500 MW and above)	70	90	160
Total	185	210	395

shown in table 18.8. The total generation includes energy required for pumping at pumped storage hydroelectric plants in the amounts of 6, 38, and 94 billion kilowatt-hours for the years 1970, 1980, and 1990, respectively.

Electric energy supplied by nuclear plants is expected to increase from less than 2 percent of the total in 1970 to nearly 50 percent by 1990. Fossil-fueled steam-electric plants will supply a decreasing portion of total energy requirements, but will supply twice as much energy in 1990 as in 1970. By 1990 the three other classes of capacity will be used largely for peaking and, although comprising about 18 percent of total capacity, will produce only about 7 percent of total generation.

TABLE 18.8

U.S. Generation by Type of Capacity, 1970, 1980, and 1990

	Capacity Thousand MW	Generation		Capacity Factor—%
		Million MWh [1]	Percent of Total	
		1970—Actual		
Conventional hydro	51.6	253	16.4	56
Pumped storage hydro	3.6	4	0.3	13
IC and gas turbine	19.2	21	1.4	12
Fossil steam	259.1	1,241	80.5	55
Nuclear	6.5	22	1.4	39
U.S. Total	340.0	1,541	100.0	52
		1980—Estimated		
Conventional hydro	68	292	9.3	49
Pumped storage hydro	27	25	0.8	10
IC and gas turbine	40	27	0.9	8
Fossil steam	390	1,895	60.9	55
Nuclear	140	874	28.1	71
U.S. Total	665	3,113	100.0	53
		1990—Estimated		
Conventional hydro	82	319	5.4	44
Pumped storage hydro	70	62	1.1	10
IC and gas turbine	75	49	0.8	7
Fossil steam	558	2,579	43.5	53
Nuclear	475	2,913	49.2	70
U.S. Total	1,260	5,922	100.0	54

[1] Includes pumping energy for pumped storage hydroelectric projects but does not include in-plant uses.

Reserve Generating Capacity

Reserve capacity is provided in electric power systems to allow for: the need to perform maintenance on generating capacity, the effects on unit output of existing physical and ambient conditions, unexpected outages of generating capacity, and characteristics of load including deviations from load estimates. As used herein, "reserve capacity" does not include an allowance to provide for possible slippage, or unscheduled delays, in bringing new facilities into service. This additional contingency must be considered in scheduling facilities to serve future loads, but it is essentially a problem of realistic scheduling rather than an item to be covered in reserve planning.

Methods of Determining Reserve Requirements

The planning techniques used by electric utility systems to establish required reserve levels can be divided into two broad categories:

1. Non-probabilistic methods
2. Probabilistic methods

Generating capacity requirements based on a non-probabilistic method have generally been determined by establishing minimum reserve requirements over the annual peak load period based on:

1. A fixed percentage of peak load, or
2. A fixed multiple of the system's largest generating unit, as for example the largest unit plus an average-sized unit.

Reliability of Calculations

In the use of these non-probabilistic methods, judgment plays a predominant role. Their only advantage is simplicity, since reserve requirements can easily be calculated once an annual peak load has been projected and the capacity of the largest unit is known. This simplicity of application, however, is offset by the inherent inability of such methods to measure, in a quantitative manner, the system reliability associated with such reserve determinations. In this approach, little consideration is given to the daily, monthly, and seasonal load patterns, or to the characteristics of generating equipment peculiar to the individual system, such as unit availabilities and the mix of unit types and sizes.

Probabilistic methods, although complex, provide an analytical means for evaluating the relative risk associated with supplying system load requirements by various means. This is generally accomplished by interrelating the load and capacity models developed for the particular system and time period under study. The load model usually consists of a series of load levels representing the full range of daily or monthly peak loads anticipated throughout the given period. The model is usually developed from historical records of daily peaks, with adjustments to reflect expected changes in load characteristics of future loads. It may also include provision for the probability of load changes because of deviations from normal conditions of weather or expected economic activity.

The capacity models used in probabilistic methods usually involve calculating the likelihood of availability of various levels of system generating capacity, based on assumed forced outage rates for the individual units. The study period is usually divided into uniform maintenance intervals so that units that would not be available for service due to scheduled maintenance would be excluded from the calculations for that particular interval. In effect, this results in a number of capacity models. The interrelation of such capacity models with load models forms the basis for evaluating the risk of capacity not being able to satisfy the load requirements. Sample calculations and more detailed explanations are given in some of the Regional Advisory Committee reports published in Parts II and III of the National Power Survey.

If generation and load models are meshed, the accumulated probability or frequency of the load exceeding available generation can be calculated. In the reliability models, as in the others, the outage rates and changes in load levels are independent events, so the probability of simultaneous occurrences of any set of conditions is the product of their individual probabilities. These figures are developed for each possible generation and load level, and the sum of all the probabilities of load in excess of available capacity represents the probability of some loss of load. Usually the probability is expressed in terms of days per year. If the probability of losing load is greater than a standard risk index, then steps must be taken to provide additional capacity (reserve) to be available when needed.

In establishing criteria for any reserve study, consideration must be given to such factors as the extent to which provision needs to be made

for actual conditions several years into the future being different from existing conditions. Factors that warrant special consideration include: (1) the increased trend toward larger unit sizes, (2) the higher forced outage rates associated with such units, at least during their initial years of service before reaching maturity and before necessary design modifications and improvements have been incorporated into subsequent units of any given series, (3) the limited amount of operating data on large units in general, and nuclear units in particular, making predictions of unit availability relatively uncertain, and (4) the uncertainties of load forecasting, particularly as they relate to departures from the normal long-range economic trend, the likelihood of occurrence of extremes in weather, and the rapid growth rate of temperature-sensitive loads.

The factors discussed above are, in large measure, uncontrollable and hence require a reasonable degree of conservatism when establishing the basic projections and assumptions to be used in the determination of future reserve requirements.

Regional Reserve Requirements

The Regional Advisory Committees developed figures for future reserve requirements using a variety of analytical methods. With this material as a base, the Commission staff made analyses for 1980 and 1990, using the same methodology for all Regions. In the staff analyses separate calculations were made to determine the composition of total reserves required in order to quantify the requirements for forced outages, load growth uncertainties, and on-peak maintenance. The results of the staff analyses for the 1990 conditions showed a national average reserve requirement of about 20 percent of peak load. Individual analyses varied within a range of 15 to 26 percent, reflecting anticipated differences in unit size, type and characteristics of generation, and characteristics of load.

On a national basis, the Advisory Committee and Commission staff studies indicated near-identical figures. There were considerable differences, however, between Regional figures and the Regional components of the staff studies, probably because of differences in outlook and analytical methods used by the various study groups. For sake of consistency, staff figures are used in this report. The characteristics of the facilities, loads, and interconnections of an individual utility system, as they actually develop, may warrant significant variations from the regional reserve figures shown.

Some of the general criteria used in the staff studies are summarized in the following paragraphs.

Reserves for Forced Outages

Using a loss of load probability technique, reserves for forced outages were provided to meet a risk index of one day in ten years. Forced outage rates ranging from 3.6 percent for 350 megawatt units to 7.5 percent for 2,100 megawatt units and above were used in the study. These rates are lower than those now being experienced but improvement is anticipated. Also, these mature forced outage rates were increased by a judgment factor of 12 percent to reflect higher rates for units in various stages of immaturity. A significant factor in the regional variations in reserves required for forced outages was the proposed size of steam-electric units with respect to peak load. Larger unit sizes, when related to a given system size, inherently require larger reserves to provide a given standard of reliability. The composition of the total capacity by types of generation was also an important factor. Forced outages, for example, are greater for thermal plants than for hydro-electric plants and are greater for a coal-fired plant than a gas-fired plant. The 1990 estimated reserves for forced outages varied between 9.2 and 12.8 percent, with a national average of about 11 percent.

Reserves for Load Growth Uncertainties

The Commission staff analyses of reserves required for load growth uncertainties were related to the historical maximum underestimates of electric utility load forecasts. The reserve requirements for this item were developed by comparing a series of one, two, three, and four-year forecasts of peak loads with actual peak loads during the 1958 and 1968 period. The national average deviation was about 5 percent, with individual analyses ranging from 4 to 7 percent.

Reserves for On-Peak Maintenance

Routine maintenance down-time varies among units, but records show a definite and relatively

TABLE 18.9

Estimated Scheduled Maintenance Requirements by Unit Size

Size of Unit, MW	Scheduled Maintenance in Percent of Time
0–600	4.2
601–1200	8.3
1201 and over	10.4

consistent relation between unit sizes and scheduled maintenance outages. The scheduled maintenance requirements used in the Commission staff analysis are shown on table 18.9.

In the staff studies, the maintenance requirements shown in table 18.9 were increased by 15 percent to allow some margin for scheduling. The total maintenance requirements for each Region were then summarized in terms of gigawatt-months to show the relation between available off-peak capacity and the maintenance needs. Any potential firm capacity exchanges between Regions were disregarded. The results of these analyses for 1990 showed that some regions would have adequate off-peak capacity to cover maintenance outages, but others were short by as much as 7 percent. Nationally, reserve requirements for scheduled maintenance averaged less than 2 percent.

Total Required Reserve Capacities

The total reserve allowances used in establishing future capacity requirements, shown in table 18.12, are those developed in the staff studies. They are not intended to be firm projections of reserve requirements in these future years. Such requirements need continuing review to reflect evolving information on equipment availability, maintenance requirements, and load forecasts.

As noted at the beginning of this section, the calculated reserves do not include an allowance for slippage of inservice dates for new generating and transmission facilities. Slippage has been an important factor, particularly in recent years, in difficulties many systems have experienced in meeting loads. Recent experiences with licensing delays, equipment troubles, construction delays, and manpower problems have dramatically illustrated the importance of providing sufficient lead times to insure that new facilities are placed in service as scheduled. Nonetheless, even with reasonably increased allowances for lead time, however, it may be appropriate to provide some contingency capacity, over and above normal reserve requirements, for unavoidable delays that cannot be counteracted by substitutions, accelerated construction, or other reasonable management devices.

Possible Patterns of Transmission to 1990

Primary Transmission Facilities

Overhead transmission lines in the United States, 23 kV nominal level and above, totaled approximately 65,000 circuit miles in 1970. The miles of overhead lines in 1970 by selected voltage classes for the total electric utility industry by National Power Survey regions, and the estimated total mileages for 1980 and 1990, are shown in table 18.10.

In addition to the overhead lines included in table 18.10, there were also in service some underground cables of 230 and 345 kilovolt ratings. However, the circuit miles were very small. In 1970, the mileages totaled a little over 60 and 90, respectively. These represent installations in highly congested urban areas where overhead circuits are impractical. Current research and development projects are expected to improve the feasibility of underground transmission, but both high costs and technological limitations have effectively restricted the use of the higher voltage cables up to this time. The highest voltage underground cable installation currently planned in the United States is one at Grand Coulee Dam utilizing self-contained, foreign-manufactured 525 kilovolt oil type cables to connect the new powerhouse section with the extra high voltage (EHV) switchyard. Ultimately it will contain nine cables with an average length of 6,500 feet. The initial installation is scheduled for completion by July 1973.

Another step in the progression to higher overhead transmission voltages was accomplished during 1969 when the first 765 kilovolt alternating current (ac) facilities were placed in service on the American Electric Power Company's system. Greatly expanded use of 500 and 765 kilovolt ac is expected for the years ahead, and it is anticipated by some that the next step above 765 kilovolt may be introduced by the end of this decade. The next ac voltage level has not been determined. Present research and development efforts encompass a range of 1,000

TABLE 18.10

Circuit Miles of Overhead Transmission Lines

Voltage Level and Year	Region						
	Northeast	East Central	Southeast	South Central	West Central	West	U.S. Total
230 kV ac							
1970	5,360	160	6,330	1,000	5,800	21,950	40,600
1980	6,140	230	17,620	2,440	6,620	26,510	59,560
1990	6,900	230	21,320	4,000	6,850	27,880	67,180
287 kV ac							
1970						1,020	1,020
1980						870	870
1990						560	560
345 kV ac							
1970	1,210	4,900		3,520	2,970	2,580	15,180
1980	3,110	9,700		7,930	6,340	5,590	32,670
1990	3,960	11,500		13,600	10,600	7,790	47,450
500 kV ac							
1970	880	600	830	1,180		3,730	7,220
1980	1,600	1,200	4,150	2,410	1,250	9,570	20,180
1990	2,200	1,500	9,020	3,480	2,440	14,760	33,400
765 kV ac							
1970		500					500
1980		2,600			570	370	3,540
1990	1,320	3,800		670	2,170	980	8,940
800 kV dc							
1970						850	850
1980	(*)					1,670	1,670
1990						1,670	1,670

*Note: DC in small amounts both overhead and underground may be placed in service in the early 80's in the Northeast Region.

to 1,500 kilovolts. Problems of progressing to these ultra-high-voltages are discussed in chapter 21, which deals with research and development needs of the electric power industry.

The first extra-high-voltage direct current (EHVdc) transmission line in the United States was placed in service in the first half of 1970 when an 800 kilovolt ($\pm$400 kV) dc connection was completed between Bonneville Power Administration's Celilo Station in northern Oregon and the Los Angeles Department of Water and Power's Sylmar Station in southern California. Although the Regional Advisory Committees' projections to 1990 do not forecast any significant additional HVdc except a proposed second circuit between the Pacific Northwest and Southwest, the Commission expects that the advantages for such types of installations will lead to other applications of HVdc, particularly in metropolitan or other heavily congested areas. HVdc may also be helpful for special purposes such as non-synchronous connections between alternating current networks.

With the exception of a major portion of the electric systems in the Texas area of the South Central Region, all of the larger utilities of the National Power Survey regions are interconnected. In a few instances, however, the interconnecting lines have insufficient capacity to assure stable operation under some conditions. This is particularly true of the east-west connections in the Rocky Mountain area where openings of the relatively weak ties occur an average of about twice daily.

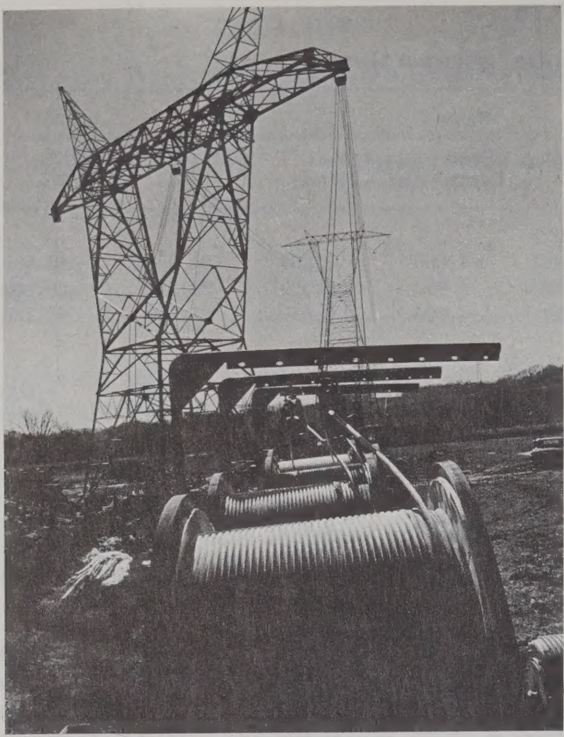

Figure 18.5—Stringing conductor bundles for a 765-kV transmission line. (American Electric Power System).

Currently there are no plans to connect the network of the Texas Interconnected Systems with the remainder of the nationwide grid but the Commission suggests that serious consideration be given to some form of interconnection. This could be one of the instances in which HVdc would constitute an effective means of permitting diversity exchanges and transfers of power in emergencies.

The 1970 transmission system of 230 kilovolt nominal level and above is shown in figure 13.1, and a possible pattern of transmission for 1990 is shown on figure 18.6. The future transmission shown on figure 18.6 is a combination of the projections submitted by the Regional Advisory Committees and additions in several areas where the Commission's staff believes more interconnection capability will be needed to provide reliability and emergency interchange capacity to assure service standards that should characterize the United States electric utility industry.

The transmission additions are based on FPC staff appraisals and judgment rather than a detailed analysis. Therefore, it is clear that the individual lines depicted should not be interpreted as specific recommendations but constitute only a possible pattern which should be viewed as a general outline to encourage further study. It is hoped that some of the suggested connections will stimulate serious consideration and study of transmission system developments which might further improve reliability and better serve some areas which are now isolated or weakly connected to the primary network covering most of the 48 contiguous States.

The present and suggested future transmission situations by regions, as discussed in the next several sections of this chapter, reflect the general premises of the Regional Advisory Committees as well as the ideas of the staff regarding transmission system developments to meet bulk power supply requirements during the next two decades. There are occasional differences in views about how some of the future developments may materialize, but these do not change the objectives and are primarily a function of technological developments and improvements which might offer better ways of meeting future needs and solving the problems of an adequate and reliable power supply.

In any long-range plan, such as illustrated on figure 18.6, it is essential to recognize that factors not now present may require substantial modification of general plans by the time they are put into actual use. Increasing emphasis on environmental considerations and right-of-way availability, may effect changes in the size, type, and location of generating plants, transmission lines, and associated facilities. Studies now underway within the industry, including those in the area of cryogenics, are directed toward reducing costs of underground transmission of both alternating current and direct current. It is conceivable that substantial amounts of direct current transmission may be found feasible for longer distances in the populous areas of the Northeast and Atlantic states before 1990. As density of population increases, the amounts of underground high voltage, high capacity circuits are expected to grow because of objections to overhead systems or the physical infeasibility of their construction.

Northeast Region

Historically, most generating plants in the Northeast Region have been located at or near

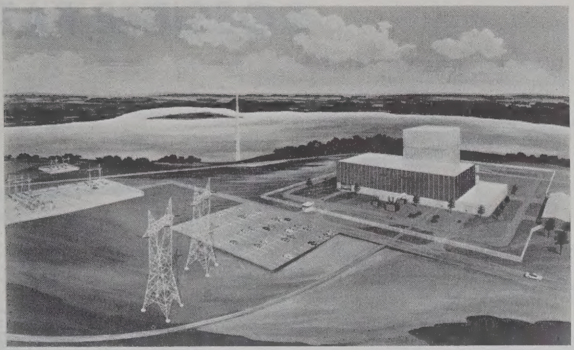

Figure 18.7—Vermont-Yankee Nuclear Power Plant.

major load centers. Consequently, high-voltage, high-capacity transmission for moving large blocks of generated power from remote plant sites to load centers was not used extensively prior to 1960, except for the lower Susquehanna, Upper Connecticut River and St. Lawrence hydroelectric developments. In New England, except for limited amounts of 230 kilovolts, the transmission network comprised primarily 69 and 115 kilovolt facilities. In New York, New Jersey and Pennsylvania, a substantial amount of 230 kilovolt transmission was in operation in addition to the underlying 138 and 115 kilovolt systems, and some 192 miles of 138 kilovolt underground lines were installed in New York City. During the 1961–1970 decade a 345 kilovolt system was constructed in New York, 500 kilovolt transmission was added in the Pennsylvania-New Jersey-Maryland (PJM) power pool, and construction of a 345 kilovolt loop was undertaken in New England.

Progressive development of interconnections and pooling among electric utilities of the Northeast lent impetus to the planning and development of more extensive and higher voltage transmission grids. From the standpoint of regional transmission considerations, developments progressed from three sub-regional groups: (a) the PJM Interconnection, (b) the New York Power Pool and (c) the New England Power Exchange (initially Connecticut Valley Electric Exchange [Convex], New England Electric System, Eastern Utilities Associates, and others).

The need for stronger ties among systems and pools, and the necessity for more extensive coordination over larger areas both for planning the expansion of physical facilities and for the daily operation of the interconnected system were stressed in the Commission's National Power Survey of 1964. The need for strengthened transmission interconnections was forcefully demonstrated by the widespread power interruption throughout New York, New England, and Ontario in November 1965, and again by the PJM power interruption in June 1967. As an outgrowth of these needs, the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Coordination Group (MAAC) were formed. These organizations have directed their attention particularly to reliability aspects of transmission and generation planning.

In the PJM area, construction of large generating units in the coal mining sections of western Pennsylvania resulted in construction of 500 kilovolt lines to transmit the power to load centers in eastern Pennsylvania and New Jersey, and to provide inter-area ties with adjacent regions. This initial 500 kilovolt system is developing into an extensive network to serve the primary transmission needs of the overall PJM Interconnection.

In the period to 1980, 345 kilovolt transmission will be extended in New England and New York and between New York and New Jersey; 500 kilovolt transmission in the PJM power pool will be expanded in the Baltimore and Washington, D.C. areas; and additional EHV connections will be made with systems in adjacent regions to strengthen ties for regional coordination. In the 1981 to 1990 decade, transmission networks will include expansion of 345 kilovolt and 500 kilovolt lines and facilities plus substantial amounts of higher voltage transmission lines. In New York and New England 765 kilovolt transmission is a logical overlay for 345 kilovolt transmission since it provides higher transmission capability and is compatible with the same voltage system already constructed in the adjoining East Central Region. Some sections of recently planned new transmission lines in New York will operate initially at 345 kilovolts but are designed for later use at 765 kilovolts. Although no voltage higher than 500 kilovolts is presently planned for construction by 1990 for the PJM pool, 1,000 kilovolts or higher transmission is a possibility in view of current research. Principal elements of an EHV grid are illustrated in the Northeast Regional Advisory Committee's report for the Northeast Region, published in Part II of the National

POSSIBLE PATTERN
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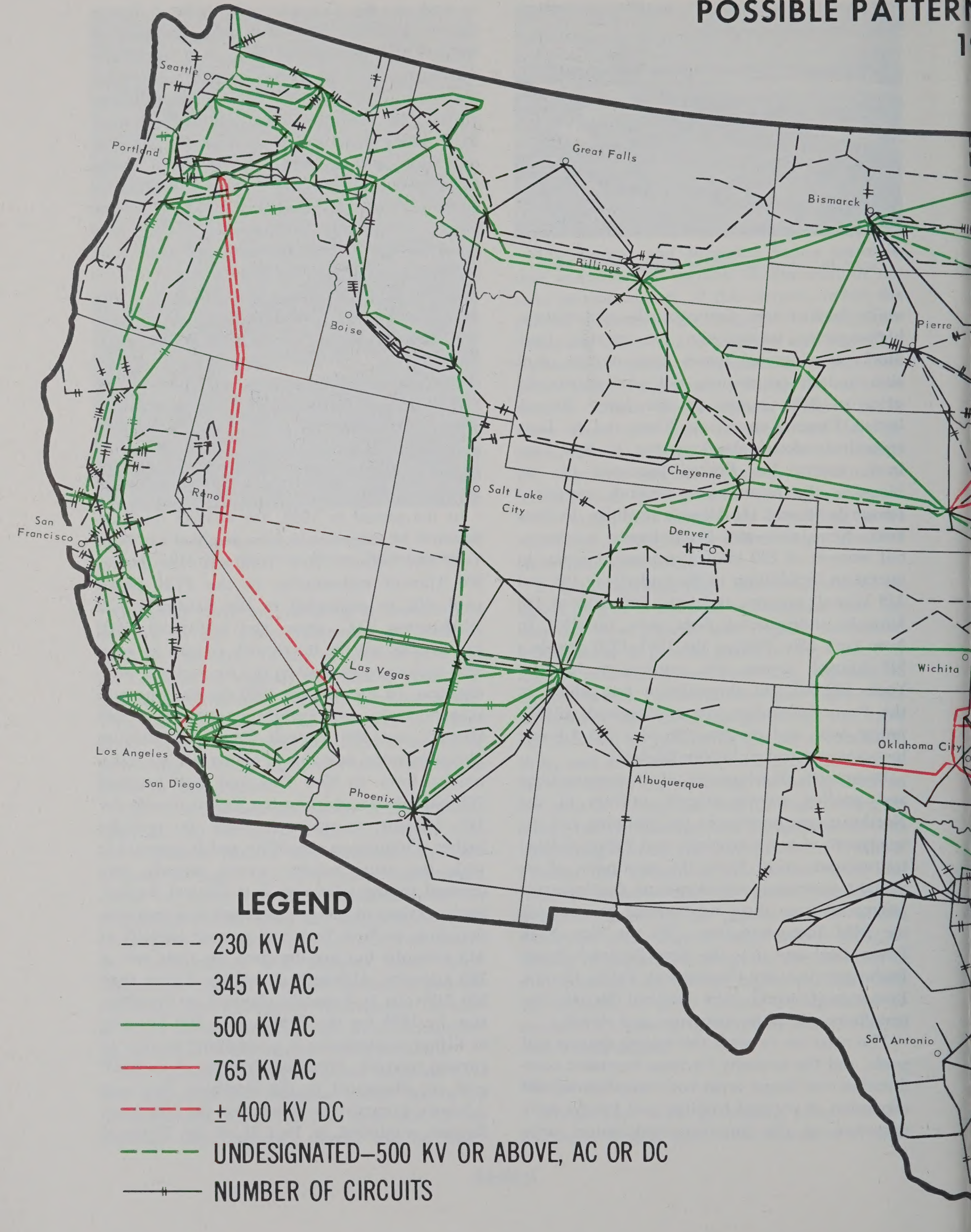

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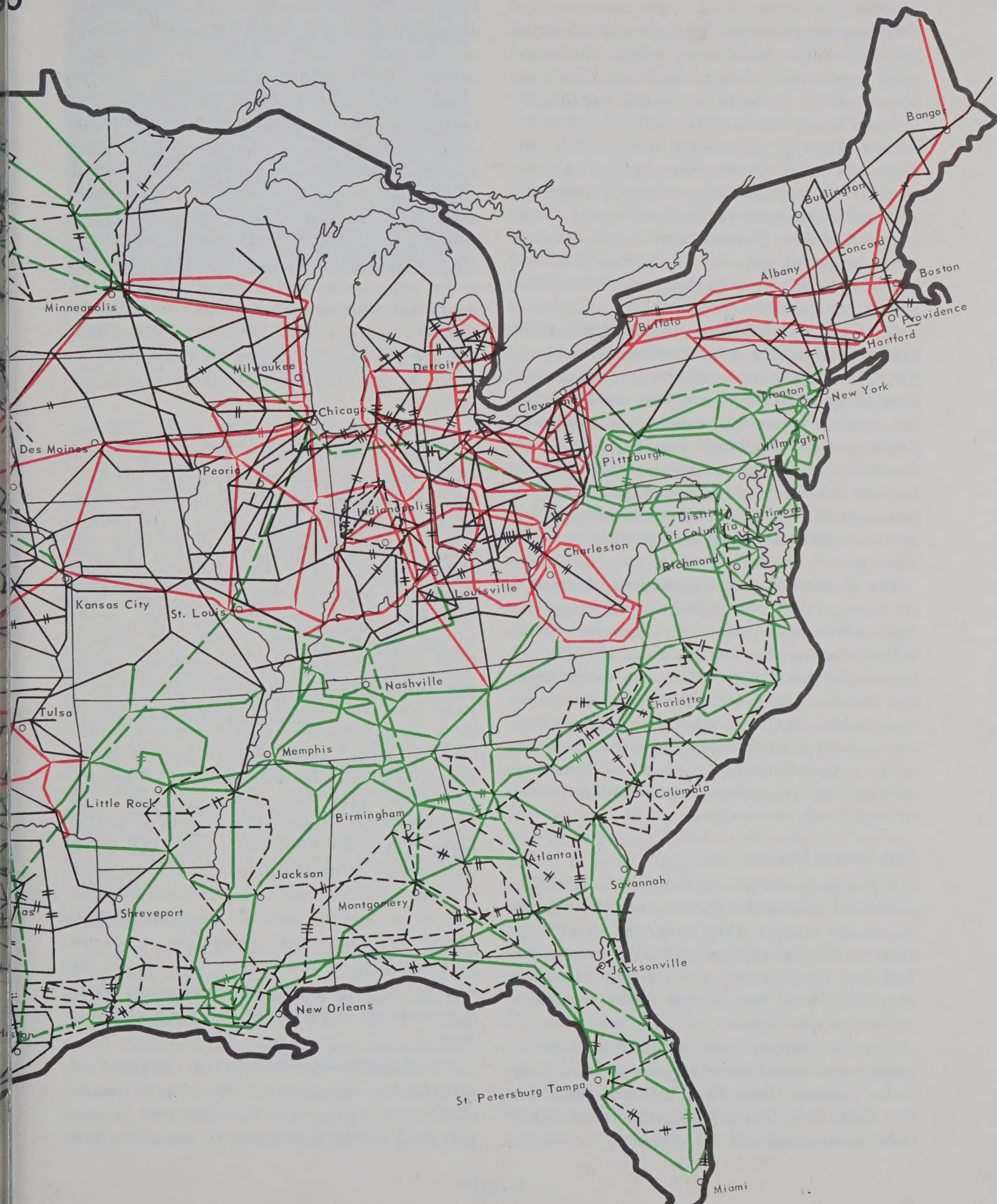

Figure 18.6

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Power Survey and are reflected in the nationwide map of the possible pattern of transmission for 1990, figure 18.6.

Connections between Canadian and U.S. utilities in the Northeast have existed for many years, and recent changes and additions have been made to improve the transfer capabilities in some areas, particularly the connections in eastern Maine which provide access to U.S. imports of power from New Brunswick and Quebec. Development of potentially large hydroelectric resources in Eastern Canada could lead to further transmission system developments to permit transfers of sizeable blocks of power into the New England and New York areas.

The principal differences in the views of the Commission and the Advisory Committees about future transmission installations are matters of scheduling. The Commission staff considers that the needs for greater transmission capability will justify initial 765 kilovolt installations by 1980 and that the parts of the region which now utilize 500 kilovolts for the backbone system will introduce by 1990 an overlay voltage appropriate at the time for use in combination with 500 kilovolts.

The Commission staff also believes that a HV dc underground system may be instituted by 1990, which would play an important role in serving the megalopolis area from Washington, D.C. to Boston. High voltage dc transmission may also be useful for establishing some nonsynchronous ties with Canadian systems and elsewhere if current technological programs indicate a desirability for limiting load frequency control areas to some maximum size that cannot be readily met in other ways.

East Central Region

The electric utilities of the East Central Region were among the pioneers in interconnecting electric systems. They have been in the forefront in the application of EHV transmission. The first 345 kilovolt and 765 kilovolt transmission lines in the United States were constructed in this region.

The 765 kilovolt lines were installed by the American Electric Power Company, as an overlay to an extensive network at 345 kilovolts. The East Central Region is perhaps the most highly interconnected area in the world.

Relatively recent transmission additions have provided direct connections between utilities in Michigan and the transmission networks in Indiana and Ohio. These provide additional indirect connections between U.S. and Canadian networks.

The East Central Regional Advisory Committee's studies indicate that substantial additions will be made to the regional transmission system by 1980—4800 circuit-miles at 345 kilovolts, 600 circuit-miles at 500 kilovolts, and 2,100 circuit-miles at 765 kilovolts. In fact, 1100 circuit-miles at 765 kilovolts and 3300 circuit-miles at 345 and 500 kilovolts were either authorized or under construction at the time the Committee's report was released at the end of 1969. Also, by 1980, many ties to adjacent electric systems outside the East Central Region are expected to be added at 345 kilovolts, 500 kilovolts, and 765 kilovolts.

In the period 1981 to 1990 about 1800 circuit-miles of 345 kilovolts, 300 circuit-miles of 500 kilovolts and 1200 circuit-miles of 765 kilovolts are expected to be placed in service, bringing the estimated total to nearly 17,000 circuit-miles of lines operating at 345 kilovolts and higher voltages. The East Central Regional Committee concludes that "By 1990, 765 kilovolts will have become the major bulk power voltage class in the area, constituting close to 4,000 circuit-miles of line. Transmission expansion at 345 kilovolts will continue both to serve local load centers and to provide, in certain areas, an underlying network to support the 765 kilovolt overlay. In the eastern portion of the region, 500 kilovolts will continue to provide the major EHV transmission voltage." The Committee also points out that while no voltage higher than 765 kilovolts is projected in its transmission expansion pattern, it is quite possible that a voltage level in the 1,200 to 1,500 kilovolt range may be initiated in the 1981–1990 period. The Committee's projections of possible patterns of future transmission development are depicted by maps at the back of its report which is reproduced in Part II of the National Power Survey.

The Commission foresees the likelihood of even further expansion of 765 kilovolt connections to adjoining areas by 1990 and expects that these will be represented by ties to the New

Figure 18.8—The Michigan Electric Power Pool Control Center has two computers which continuously monitor and direct 67 generating units in 13 power plants of the Detroit Edison Company and Consumers Power Company.

York area and heavier ties to parts of the West Central Region.

As mentioned above, the East Central Regional Advisory Committee suggests the adoption of a higher transmission voltage and the Commission also believes that there is a strong likelihood of introduction of a voltage higher than 765 kilovolts before 1990. One of the first installations might be a backbone line from north to south through the Region, linking with companion facilities to permit interregional power transfers with areas to the south and as far away as Florida and Texas.

It is likely that HVdc may be advantageous for use in the areas of heaviest population concentration where high capacity underground transmission is likely to become a necessity. Also HVdc may be an attractive application for submarine transmission connections in the Great Lakes area.

Southeast Region

Prior to the mid 1960's, the electric consumers of the Southeast generally were served from facilities supplied by a primary network of 161 and 230 kilovolt circuits. At that time, TVA initiated construction of 500 kilovolt transmission overlaying its 161 kilovolt network in order to provide large transfer capacity for exchange of seasonal diversity with systems in the South Central Region. Its first 500 kilovolt line began operation on April 1, 1966. About the same time, the Virginia Electric and Power Company began construction of the Mt. Storm mine-mouth stream-electric plant in West Virginia and 500 kilovolts circuits to transmit its output to northern Virginia and Richmond load centers. This 500 kilovolt line was placed in operation on February 12, 1966. In the remainder of the Region, 230 kilovolt and lower voltage transmission had sufficed until recently. The advent of large central station nuclear-fueled and fossil-fueled generation, the economy of EHV lines carrying large outputs considerable distances to load centers, and the need for strengthened as well as additional coordinating ties among electric systems will require considerable expansion of the 500 kilovolt system if effective utilization of power resources is to be accomplished. Largely in the northern sections of the Region and in Florida more than 4,100 miles of 500 kilovolt lines have been projected by 1980, to be increased throughout the region to about 9,000 miles by 1990. In addition, further expansion of the underlying 230 kilovolt and lower voltage transmission lines and facilities will be required. The Southeast Regional Advisory Committee's report, included in Part II of the Survey, contains maps depicting possible patterns of transmission for 1980 and 1990.

Interconnection of facilities and coordination of construction and operations among utilities are being advanced, and by 1980 full advantage will be taken of seasonal and other assured diversities within the region. Of particular note are the present and projected high capacity interconnections between Southeast Region utilities and neighboring systems in the East Central Region and those in the PJM Pool of the Northeast Region. Most of the new ties are expected to be at 500-to-500 kilovolts and at 500-to-765 kilovolts, all capable of very substantial transfers of capacity in the interests of reliability and economy.

It is projected that the beginning of interregional connections at a voltage higher than 765 kilovolts will have been started before 1990 and that the Southeast Region is likely to be involved in such connections. It appears appropriate to provide stronger transmission connections within the State of Florida and stronger ties between the Florida peninsula and the rest of the nationwide network by installing new lines

north and south through the State and thence to trunk connections to the north and around the Gulf coast to Louisiana and Texas.

It also seems appropriate to provide connections of greater capability along the Atlantic coastal area in a configuration which provides for increased transmission capability from east central North Carolina to northeastern Florida.

South Central Region

The South Central Region presently has two major networks which are not interconnected with each other. One, the Southwest Power Pool and associated systems, has been in operation since the early days of World War II. The South Central Electric Companies, a group within this pool, exchanges 1,500 megawatts of seasonal diversity capacity with TVA, over a 500 kilovolt and 345 kilovolt transmission grid. The other transmission network, known as the Texas Interconnected System, is an isolated coordinating organization located wholly within the state of Texas. Member systems are, for the most part, interconnected at 345 kilovolts in the north and 230 kilovolts in the south, with north-south ties at 345 kilovolts. Additional pooling and coordinating groups in the South Central Region include the Missouri-Kansas Pool, the Texas Municipal Pool, and the Missouri Integration Arrangement. Pooling and coordinating arrangements are more specifically described, and their memberships identified, in the South Central Regional Advisory Committee's report published in Part III of the National Power Survey.

As shown on maps included with its report, the South Central Regional Advisory Committee concluded that transmission and coordinating needs in the period to 1990 could be accomplished largely by expansion of the 345 kilovolt and 500 kilovolt transmission systems. Commencement of a 765 kilovolt overlay in Oklahoma with extensions to Amarillo and Shreveport by 1990 is projected. The Committee's possible patterns of future expension include approximately 7930 circuit-miles of 345 kilovolt and 2410 circuit-miles of 500 kilovolt transmission lines by 1980. The total circuit miles by 1990 are projected to be about 13,600 at 345 kilovolts, 3480 at 500 kilovolts, and 670 at 765 kilovolts.

The major difference between the South Central Regional Advisory Committee's projections of future transmission configurations and those in this report involves interconnection of the Texas Interconnected System group with the nationwide grid of other utility systems. The Commission believes that the emergency interchange possibilities and the efficient use of generating capacity reserves warrant the interconnection of these networks. As mentioned earlier, the possibility of HVdc links to establish such connections should be consideerd if there are convincing arguments that ac connections would be detrimental to system stability and power supply reliability.

The pattern of interconnection as shown on the future transmission map includes ties from Texas to relatively high capacity circuits to the east, north and west. The projections of this report suggest consideration of higher capacity connections that would permit greater flows between the South Central Region and the TVA 500 kilovolt system, the St. Louis and Kansas City areas, and the Four Corners area of the West Region which has existing and planned heavy connections to southern California. It is expected that such connections, at a voltage level of 765 kilovolts or higher, will be installed prior to 1990.

West Central Region

In late 1963 and early 1964 a group of West Central Region utilities known as Mid-Continent Area Power Planners (MAPP) developed a coordinated plan for high voltage transmission linking major load centers in the ten-state upper midwest area. This consists of 345 kilovolt lines linking the Twin Cities (Minneapolis-St. Paul) with Milwaukee and Chicago; a 345 kilovolt line from the Twin Cities through Iowa to St. Louis; a 345 kilovolt line from St. Louis to Kansas City, St. Joseph, and Omaha; and a 345 kilovolt line from Omaha to Sioux City and back to Minneapolis. In addition, connecting links at 345 kilovolts and 230 kilovolts are included in an overall integrated network, most of which are now operating. The remainder is expected to be completed by 1972.

In the period 1970 to 1980, significant expansion of the 345 kilovolt system is projected and the first installation of 500 kilovolt transmission may be feasible, extending from the Twin

Cities area to the northwest to Manitoba and westward into the Missouri River Basin. It is also anticipated that 765 kilovolt electric circuits from the East Central region will extend from the Chicago area, southwestward to St. Louis, and westward into Iowa. By 1990, the transmission system in the eastern part of the Region would have additional 765 kilovolt transmission and in the western part the extensive 230 kilovolt network will be overlain with 500 kilovolts.

In 1970, the West Central region had 2,970 circuit-miles of 345 kilovolt lines and 5,800 circuit-miles of 230 kilovolt lines. By 1980, the region is expected to have 570 circuit-miles of 765 kilovolt, 1,250 circuit-miles of 500 kilovolt, 6,340 circuit-miles of 345 kilovolt, and 6,620 circuit-miles of 20 kilovolt lines. By 1980, the region would have an estimated 2,170 circuit-miles of 765 kilovolt, 2,440 circuit-miles of 500 kilovolt, 10,600 circuit-miles of 345 kilovolt, and 6,850 circuit-miles of 230 kilovolt lines.

There is a significant amount of transmission coordination between the West Central Region and other Regions. Interregional coordination of transmission networks is accomplished through arrangements between systems of MAIN (Mid-America Interconnected Network) in the eastern part of West Central Region and ECAR (East Central Area Reliability Coordination Agreement) in the East Central Region, between systems in the southern part of the West Central Region and the South Central Region, and between systems in the western part of the West Central Region and the West Region.

International coordination was an important part of planning and construction of transmission connections with the Manitoba Hydro system in Canada. The new 145 mile, 230 kilovolt, circuit extending from Winnipeg, Manitoba to Grand Forks, North Dakota will permit coordination with the Manitoba Hydro Electric Board for power and energy transactions.

The Nelson River in Manitoba has a potential for development of five to six million kilowatts of hydro capacity. The first phase of major development of the Nelson River entails construction of a twelve-unit hydro-electric station at Kettle Rapids near Gillam, Manitoba. The plant will have slightly more than 1,200 megawatts of generating capacity. The first four units (406 MW total) are expected to be in service late in 1971. Power from the station is to be delivered to Winnipeg over two $\pm$ 450 kilovolt direct current transmission lines, each about 600 miles long. In its report, the West Central Regional Advisory Committee stated: "It appears that in the 1975–80 period a substantial tie, possibly dc, between Winnipeg, the Iron Range and the Twin Cities may be feasible to utilize about 800 megawatts of capacity from the Nelson River."

Review of transmission capabilities and load center power requirements indicates the possibility of need for somewhat greater transfer capabilities under assumed worst contingencies than those projected by the Regional Advisory Committee for future years. It seems appropriate to consider heavier ties between the Minneapolis-Lake Michigan areas and the West Region. Also, sufficient transfer capability to permit power generated in the Wyoming-Montana coal district to flow into the Milwaukee and Chicago load areas may be economically feasible.

Use of EHVdc to provide more stable connections between the network west of the Rockies and the eastern interconnected network would directly involve parts of the West Central Region and could foster the use of EHVdc as a transmission medium in this area prior to 1990.

West Region

As in the case of the other five Regions, the report of the West Regional Advisory Committee for the West Region includes a detailed presentation of possible patterns of transmission networks for 1980 and 1990.

Because of the early development of hydroelectric sites remote from load centers, the West Region was the first to use high voltages for transmission. It was also the first to utilize high voltage direct current transmission. As of 1970, the entire region is interconnected by transmission lines of various voltages except for a small section in northwest Texas and the southwest corner of Oklahoma. A chief characteristic of the Region is the Western transmission loop, comprising 500 kilovolt ac circuits and an 800 kilovolt dc circuit on the west side; 500 kilovolt, 287 kilovolt and 230 kilovolt ac circuits in California and 500 kilovolt and 245 kilovolt ac circuits in Arizona on the south side; and 230

Figure 18.9—Control Center of Seattle City Light.

kilovolt ac circuits on the eastern and northern sides.

Similar to other areas farther east there are cross-border transmission connections between Canadian utilities and U.S. systems in the Northwest. Coordinated planning and operation is practiced to take advantage of the potentials afforded by the hydroelectric resources common to the area.

The patterns of transmission in the Northwest for 1980 and 1990 depict principal transmission voltages of 500 kilovolts, 345 kilovolts, and 230 kilovolts, with some 287 kilovolts. By 1980, additional 500 kilovolt transmission lines would be added, a dc circuit with a voltage level of about ±400 kilovolts would be constructed from The Dalles in Oregon to near Hoover dam, and ac circuits with voltages above 500 kilovolts would be added in western Washington. By 1990, additional 500 kilovolt ac circuits as well as circuits with voltages above 500 kilovolts would be constructed in the western part and 345 kilovolt circuits in the eastern part.

In the Southwest, additional 500 kilovolt circuits are anticipated.

In the Wyoming-Colorado area, additional 230 kilovolt ac transmission lines are forecast to meet most of the expansion requirements to 1980. By 1990, there would be additional transmission circuits at 500 kilovolts, 345 kilovolts and 230 kilovolts.

In the New Mexico–northwest Texas–southwest Oklahoma area, the eastern and western parts would be interconnected at 345 kilovolts by 1980. The projections of the West Regional Advisory Committee indicate a number of new circuits but depict the transmission requirements being met by additional 345 kilovolt ac transmission facilities through 1990.

As of 1970, there were four major 230 kilovolt transmission lines connecting the West and the West Central Regions. By 1980, one 345 kilovolt and six 230 kilovolt transmission lines connecting to the West Central Region and three 345 kilovolt transmission lines connecting the West Region to the South Central Region are anticipated. The 1990 projection includes three 500 kilovolt, one 345 kilovolt, and six 230 kilovolt transmission lines from the West Region to the West Central Region and, by conversion, two 500 kilovolt and one 765 kilovolt lines to the South Central Region.

The need for more stable operation of the western loop is considered to justify heavier transmission connections than those projected by the West Regional Advisory Committee. The heavier connections should prevent the relatively frequent interruptions which have been experienced in some areas because of disturbances affecting the Pacific Northwest-Southwest ties. Also, stronger ties to the east are visualized as well as lines of adequate capacity connecting to the South Central and West Central Regions. As pointed out earlier in this chapter, HVdc might offer a practical solution to the problem of stable interconnection for reliable transfer of power at a reasonable cost. Consideration of HVdc to accomplish these objectives is recommended.

Seasonal Diversity of Peak Demands

Geographical orientation of electric utility systems and the dominant weather patterns under which they operate are the primary causes of seasonal diversity. In some areas, that diversity may have economic significance in the future operation and planning of electric bulk power supply. Nearly all utility systems have higher peak demands in the summer and winter than in the spring and fall. The difference between the summer and winter peaks is termed seasonal diversity. Systems which usually peak in the winter may have surplus capacity available during the summer months. Similarly, those

which usually peak in the summer may have idle capacity available during the winter. The significance of seasonal diversity lies in the availability of capacity over and above that required for maintenance purposes, required reserves, and serving loads. Seasonal diversity becomes important when two systems within economical transmission distance have substantially different seasonal load characteristics. It is often possible under such circumstances for a winter peaking system to supply power during the summer months to assist in meeting the loads of a summer-peaking system. With such an exchange, surplus summer capacity on the winter-peaking system is operated to produce income, and on the summer-peaking system investment in generating capacity is postponed. During the winter the exchange may be reversed. The seasonal exchange of power thus benefits each system. If each system is to share equally in the benefits, the theoretical maximum amount of the seasonal exchange is equal to one half of the seasonal diversity of the system having the smaller amount.

The magnitude of seasonal diversity was estimated in 1968 by totaling the differences between summer and winter loads of the utility systems in each Power Supply Area to obtain a PSA seasonal diversity and in turn totaling the PSA seasonal diversities to obtain a value for each of the regions. These estimates of seasonal diversities for 1970 and 1990 are shown by power supply areas on figure 18.10, and by regions in table 18.11.

Analyses of actual 1970 loads and updated projections of 1980 loads by electric reliability councils, indicate a greater trend to summer peaks than was anticipated in 1968. On the basis of the updated projections both the Northeast and East Central regions would experience annual peak demands in summer instead of winter. Thus, the opportunities for utilizing seasonal diversities may be less than shown on figure 18.10 and table 18.11. Significantly, the usable portion of seasonal diversity is limited to that portion that remains after allowances have been made for scheduled maintenance. This means that in those regions where seasonal diversity is expected to be a small percentage of regional peak load, little seasonal diversity, may be available to provide opportunity for exchanges.

Possible Patterns of Power Supply by Regions

Energy resources available to individual regions will largely determine the composition of future generating capacity. The East Central and South Central Regions, having large reserves of fossil fuels, will continue to rely principally on fossil-fueled steam-electric plants. In the Northeast and West Central Regions, new installations of base load capacity will be predominantly nuclear. By 1990, it is anticipated that nuclear capacity will comprise more than 50 percent of total capacity in these two regions. New installations of nuclear capacity will also exceed other types of capacity in the Southeast and West Regions. The bulk of new conventional hydroelectric capacity will be installed in the West Region. New pumped storage hydroelectric installations will be distributed among all regions, with the largest capacity anticipated in the Northeast Region.

Table 18.12 shows a possible pattern by regions of generating capacity by type of prime

TABLE 18.11

Estimated Differences Between August and December, Peak Loads by Regions, 1970, 1980, and 1990

NPS Region	1970 Megawatts	1970 Month of Higher Peak	1980 Megawatts	1980 Month of Higher Peak	1990 Megawatts	1990 Month of Higher Peak
Northeast	85	Dec.	455	Dec.	1,715	Dec.
East Central	1,410	Dec.	2,420	Dec.	3,990	Dec.
Southeast	1,256	Dec.	1,110	Aug.	7,478	Aug.
West Central	3,120	Aug.	10,090	Aug.	16,550	Aug.
South Central	12,265	Aug.	27,935	Aug.	56,100	Aug.
West	2,855	Dec.	5,300	Dec.	9,740	Dec.

ESTIMATED DIFFERENCES BETWEEN AUGUST AND DECEMBER PEAK LOADS

Within Each Power Supply Area

1970

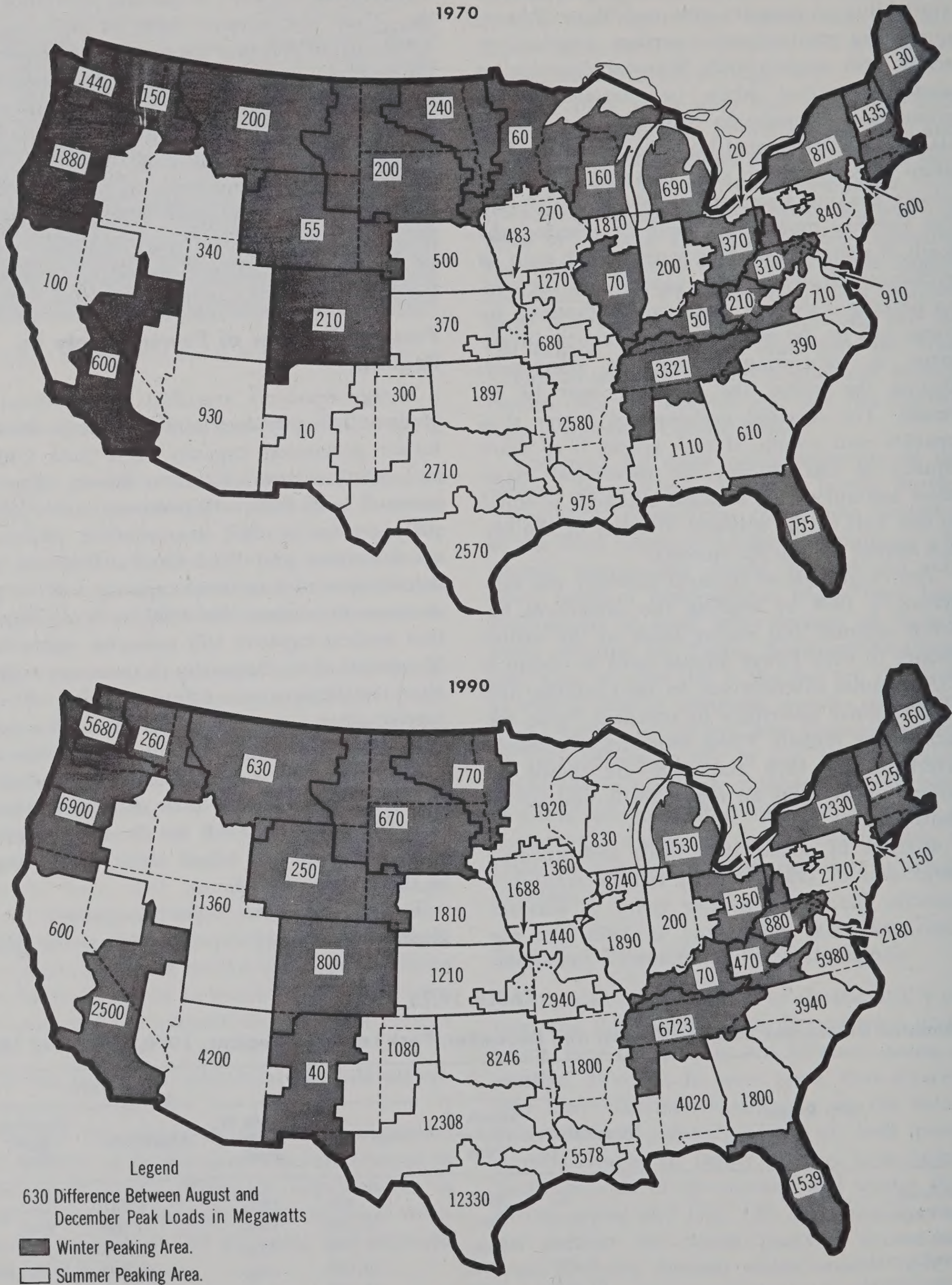

Figure 18.10

TABLE 18.12

Generating Capacity by Type of Prime Mover; Peak Demand, and Reserve Capacity by Regions

	1970		1980		1990	
	MW	Percent	MW	Percent	MW	Percent
Northeast						
Conventional hydro	5,800	8.9	7,000	6.2	7,000	3.5
Pumped storage hydro	1,800	2.8	9,000	8.0	19,000	9.4
IC and gas turbines	6,300	9.7	9,000	8.0	13,000	6.5
Fossil steam	47,500	73.2	47,000	41.5	47,000	23.4
Nuclear	3,500	5.4	41,000	36.3	115,000	57.2
Total capacity	64,900	100.0	113,000	100.0	201,000	100.0
Peak demand	52,900		93,000		165,000	
Reserve capacity	12,000		20,000		36,000	
Reserves in percent of peak	23		21		22	
East Central						
Conventional hydro	1,000	1.8	2,000	1.9	3,000	1.6
Pumped storage hydro	100	0.2	4,000	3.9	14,000	7.6
IC and gas turbines	2,400	4.4	7,000	6.8	12,000	6.5
Fossil steam	51,200	93.1	77,000	74.8	115,000	61.7
Nuclear	300	0.5	13,000	12.6	42,000	22.6
Total capacity	55,000	100.0	103,000	100.0	186,000	100.0
Peak demand	44,000		82,000		148,000	
Reserve capacity	11,000		21,000		38,000	
Reserves in percent of peak	25		25		26	
Southeast						
Conventional hydro	9,300	14.6	11,000	8.3	13,000	5.1
Pumped storage hydro	100	0.2	4,000	3.0	13,000	5.1
IC and gas turbines	2,700	4.2	6,000	4.5	14,000	5.5
Fossil steam	51,600	81.0	77,000	58.3	121,000	47.4
Nuclear	0	0.0	34,000	25.8	94,000	36.9
Total capacity	63,700	100.0	132,000	100.0	255,000	100.0
Peak demand	52,900		110,000		211,000	
Reserve capacity	10,800		22,000		44,000	
Reserves in percent of peak	20		20		21	

TABLE 18.12—Continued

	1970		1980		1990	
	MW	Percent	MW	Percent	MW	Percent
West Central						
Conventional hydro	3,500	8.2	3,000	3.7	3,000	2.0
Pumped storage hydro	400	0.9	2,000	2.4	4,000	2.6
IC and gas turbines	4,200	9.9	8,000	9.8	14,000	9.2
Fossil steam	33,000	77.5	50,000	60.9	54,000	35.6
Nuclear	1,500	3.5	19,000	23.2	77,000	50.6
Total capacity	42,600	100.0	82,000	100.0	152,000	100.0
Peak demand	35,700		69,000		128,000	
Reserve capacity	6,900		13,000		24,000	
Reserves in percent of peak	19		19		19	
South Central						
Conventional hydro	2,300	4.7	3,000	2.8	4,000	1.9
Pumped storage hydro	100	0.2	3,000	2.8	8,000	3.8
IC and gas turbines	2,100	4.3	7,000	6.6	14,000	6.6
Fossil steam	44,400	90.8	85,000	80.2	139,000	65.9
Nuclear	0	0.0	8,000	7.6	46,000	21.8
Total capacity	48,900	100.0	106,000	100.0	211,000	100.0
Peak demand	40,600		91,000		182,000	
Reserve capacity	8,300		15,000		29,000	
Reserves in percent of peak	20		16		16	
West						
Conventional hydro	29,700	45.8	42,000	32.5	52,000	20.4
Pumped storage hydro	1,100	1.7	5,000	3.9	12,000	4.7
IC and gas turbines	1,500	2.3	3,000	2.3	8,000	3.2
Fossil steam	31,400	48.4	54,000	41.9	82,000	32.1
Nuclear	1,200	1.8	25,000	19.4	101,000	39.6
Total capacity	64,900	100.0	129,000	100.0	255,000	100.0
Peak demand	49,600		110,000		216,000	
Reserve capacity	15,300		19,000		39,000	
Reserves in percent of peak	31		17		18	

mover for the years 1970, 1980, and 1990. Also shown are the estimated annual peak loads and the reserve requirements.

The regional needs for new generating capacity for the 10-year periods 1971–1980 and 1981–1990 are shown by type of prime mover in table 18.13. The needs shown for fossil steam include capacity which will be required to replace existing generating units which are assumed to be retired after 35 years of service.

The numbers and sizes of fossil-fueled and nuclear steam-electric units projected by regions for 1980 and 1990 are shown in table 18.14. The regional amounts are a breakdown of the corresponding national totals shown in tables 18.5 and 18.6.

Actual generation by regions in 1970, and the estimated generation in 1980 and 1990, by type of generating capacity are shown in table 18.15. Pronounced changes in the patterns of generation are expected to occur in all regions. Because of the increasing reliance on new nuclear plants, over the next two decades fossil-fueled steam-electric plants will supply a decreasing proportion of total generation in each of the six regions. In absolute quantities, however, fossil-fueled generation will increase in all regions except the Northeast. By 1990, nuclear plants are expected to be the source of more than 60 percent of total generation in two regions, Northeast and West Central.

TABLE 18.13

New Capacity Needs by Regions and Type of Prime Mover

Type of Prime Mover	Northeast MW	East Central MW	Southeast MW	West Central MW	South Central MW	West MW	U.S. Total MW
1971–1980							
Conv. hydro	1,000	1,000	2,000	0	0	12,000	16,000
P. S. hydro	7,000	4,000	4,000	1,000	3,000	4,000	23,000
IC and GT	3,000	5,000	3,000	4,000	5,000	1,000	21,000
Fossil steam	8,000	33,000	27,000	20,000	43,000	25,000	156,000
Nuclear	37,000	13,000	34,000	18,000	8,000	24,000	134,000
Total	56,000	56,000	70,000	43,000	59,000	66,000	350,000
1981–1990							
Conv. hydro	0	1,000	2,000	0	1,000	10,000	14,000
P. S. hydro	10,000	10,000	9,000	2,000	5,000	7,000	43,000
IC and GT	4,000	5,000	8,000	6,000	7,000	5,000	35,000
Fossil steam	11,000	51,000	57,000	13,000	62,000	35,000	229,000
Nuclear	74,000	29,000	60,000	58,000	38,000	76,000	335,000
Total	99,000	96,000	136,000	79,000	113,000	133,000	656,000

TABLE 18.14

Steam-Electric Capacity by Unit Sizes, 1980 and 1990

Unit Size MW	Fossil Steam				Nuclear			
	1980		1990		1980		1990	
	Capacity MW	No. of Units	Capacity MW	No. of Units	Capacity MW	No. of Units	Capacity MW	No. of Units
Northeast								
600 and less	38,000	300	27,700	131	2,600	7	2,600	7
601 to 1,200	6,200	7	7,800	8	26,400	28	34,300	36
1,201 to 1,800	2,800	2	7,500	5	12,000	8	43,100	25
1,801 to 2,400			4,000	2			27,100	13
2,401 to 3,000							7,900	3
Total	47,000	309	47,000	146	41,000	43	115,000	84
East Central								
600 and less	46,000	374	37,100	186	300	3	300	3
601 to 1,200	27,000	32	43,900	49	10,000	12	24,000	25
1,201 to 1,800	4,000	3	21,000	14	2,700	2	11,200	7
1,801 to 2,400			13,000	6			4,000	2
2,401 to 3,000							2,500	1
Total	77,000	409	115,000	255	13,000	17	42,000	38
Southeast								
600 and less	50,900	323	44,900	195	500	1	2,200	5
601 to 1,200	23,300	27	47,100	45	24,500	26	41,000	47
1,201 to 1,800	2,800	2	21,000	14	9,000	6	32,800	22
1,801 to 2,400			8,000	4			12,400	6
2,401 to 3,000							5,600	2
Total	77,000	352	121,000	258	34,000	33	94,000	82

TABLE 18.14—Continued

Unit Size MW	Fossil Steam 1980 Capacity MW	Fossil Steam 1980 No. of Units	Fossil Steam 1990 Capacity MW	Fossil Steam 1990 No. of Units	Nuclear 1980 Capacity MW	Nuclear 1980 No. of Units	Nuclear 1990 Capacity MW	Nuclear 1990 No. of Units
West Central								
600 and less	39,900	460	36,700	209	8,300	18	9,500	20
601 to 1,200	8,700	10	7,300	10	7,700	9	39,100	41
1,201 to 1,800	1,400	1	6,000	4	3,000	2	15,000	10
1,801 to 2,400			4,000	2			8,200	4
2,401 to 3,000							5,200	2
Total	50,000	471	54,000	225	19,000	29	77,000	77
South Central								
600 and less	62,600	480	72,000	312			600	1
601 to 1,200	21,100	26	38,000	51	6,700	7	26,400	29
1,201 to 1,800	1,300	1	21,000	14	1,300	1	15,000	10
1,801 to 2,400			8,000	4			4,000	2
2,401 to 3,000								
Total	85,000	507	139,000	381	8,000	8	46,000	42
West								
600 and less	35,600	321	43,600	221	1,500	5	2,700	7
601 to 1,200	15,700	18	18,900	22	17,500	19	48,200	49
1,201 to 1,800	2,700	2	13,500	9	6,000	4	32,000	21
1,801 to 2,400			6,000	3			10,300	5
2,401 to 3,000							7,800	3
Total	54,000	341	82,000	255	25,000	28	101,000	85

TABLE 18.15

Estimated Generation by Regions and Type of Capacity, 1970, 1980, and 1990[1]

	1970—Actual			1980—Estimated			1990—Estimated		
	Capacity MW	Generation 10^6 MWh	Generation % of Total	Capacity MW	Generation 10^6 MWh	Generation % of Total	Capacity MW	Generation 10^6 MWh	Generation % of Total
Northeast									
Conv. hydro	5,800	35	11.9	7,000	34	6.5	7,000	35	3.7
P.S. hydro	1,800	3	1.0	9,000	8	1.5	19,000	17	1.8
I.C. and G.T.	6,300	6	2.0	9,000	6	1.2	13.000	9	1.0
Fossil steam	47,500	238	80.7	47,000	228	43.2	47,000	190	20.2
Nuclear	3,500	13	4.4	41,000	251	47.6	115,000	691	73.3
Total	64,900	295	100.0	113,000	527	100.0	201,000	942	100.0
East Central									
Conv. hydro	1,000	4	1.5	2,000	4	0.8	3,000	6	0.7
P.S. hydro	100	...	...	4,000	4	0.8	14,000	12	1.3
I.C. and G.T.	2,400	2	0.8	7,000	5	1.0	12,000	8	0.9
Fossil steam	51,200	254	97.7	77,000	398	80.8	115,000	604	67.5
Nuclear	300	...	...	13,000	82	16.6	42,000	265	29.6
Total	55,000	260	100.0	103,000	493	100.0	186,000	895	100.0
Southeast									
Conv. hydro	9,300	30	9.8	11,000	37	5.8	13,000	38	3.1
P.S. hydro	100	1	0.3	4,000	4	0.6	13,000	11	0.9
I.C. and G.T.	2,700	4	1.3	6,000	4	0.6	14,000	9	0.7
Fossil steam	51,600	270	88.6	77,000	383	59.7	121,000	573	47.0
Nuclear	0	0	0.0	34,000	214	33.3	94,000	590	48.3
Total	63,700	305	100.0	132,000	642	100.0	255,000	1,221	100.0
West Central									
Conv. hydro	3,500	15	8.3	3,000	14	3.8	3,000	14	2.0
P.S. hydro	400	...	0.0	2,000	2	0.5	4,000	4	0.6
I.C. and G.T.	4,200	5	2.8	8,000	5	1.3	14,000	9	1.3
Fossil steam	33,000	158	87.3	50,000	235	63.0	54,000	220	31.2
Nuclear	1,500	3	1.6	19,000	117	31.4	77,000	457	64.9
Total	42,600	181	100.0	82,000	373	100.0	152,000	704	100.0

TABLE 18.15—Continued

	1970—Actual			1980—Estimated			1990—Estimated		
	Capacity MW	Generation 10^6 MWh	Generation % of Total	Capacity MW	Generation 10^6 MWh	Generation % of Total	Capacity MW	Generation 10^6 MWh	Generation % of Total
South Central									
Conv. hydro	2,300	5	2.6	3,000	8	1.8	4,000	9	1.0
P.S. hydro	100	...	...	3,000	3	0.7	8,000	7	0.8
I.C. and G.T.	2,100	3	1.5	7,000	5	1.1	14,000	9	1.5
Fossil steam	44,400	188	95.9	85,000	382	85.2	139,000	596	65.7
Nuclear	0	0	0.0	8,000	50	11.2	46,000	290	31.8
Total	48,900	196	100.0	106,000	448	100.0	211,000	911	100.0
West	39,800			47,000			64,000		
Conv. hydro	29,700	164	54.0	42,000	195	31.0	52,000	217	17.4 ~18.3
P.S. hydro	1,100	...	0.0	5,000	4	0.6	12,000	11	0.9
I.C. and G.T.	1,500	1	0.3	3,000	2	0.3	8,000	5	0.4
Fossil steam	31,400	133	43.7	54,000	269	42.7	82,000	396	31.7
Nuclear	1,200	6	2.0	25,000	160	25.4	101,000	620	49.6
Total	64,900	304	100.0	129,000	630	100.0	255,000	1,249	100.0
Contiguous United States							152,000		
Conv. hydro	51,600	253	16.4	68,000	292	9.4	82,000	319	5.4
P.S. hydro	3,600	4	0.3	27,000	25	0.8	70,000	62	1.0
I.C. and G.T.	19,200	21	1.4	40,000	27	0.9	75,000	49	0.8
Fossil steam	259,100	1,241	80.5	390,000	1,895	60.9	558,000	2,579	43.5
Nuclear	6,500	22	1.4	140,000	874	28.0	475,000	2,913	49.3
Total	340,000	1,541	100.0	665,000	3,113	100.0	1,260,000	5,922	100.0

[1] Excludes in-plant uses but includes pumping energy for pumped storage projects.

FPC news (4-14-72, 8 6) says 153,000 hydro
Does this mean 1,000 for Alaska?

CHAPTER 19

OUTLOOK FOR ELECTRIC POWER COSTS

Introduction

Few sectors of American industry can match the electric power industry's achievements in providing service to its consumers at declining unit costs. During the 42 years from 1926 to 1968, the average price paid by consumers for a kilowatt-hour for electricity was reduced from 2.7 to 1.5 cents, while the Consumer Price Index rose from 51 to 100 (1968 = 100).[1] Adjusted for the decline in the purchasing power of the dollar, as measured by the Consumer Price Index, the average price of a kilowatt-hour in 1968 was only 28 percent of its price in 1926.

The numerous factors bearing, directly or indirectly, on the past and future cost of furnishing electric service have been discussed in earlier chapters. This chapter reflects the combined effect of these factors in appraising the outlook for the cost of electricity to the year 1990. The projection should be interpreted not as a precise forecast but rather an estimate based on various assumptions regarding future developments. Many developments affecting these assumptions are not within the industry's control. None can be predicted with complete confidence.

In the 1964 National Power Survey it was estimated that the average cost of power to the consumer, on the basis of 1962 equivalent dollars, could decline from 1.68 cents per kilowatt-hour in 1962 to 1.23 cents in 1980. Interpolating, the projected target cost in 1968 would be approximately 1.53 cents in terms of 1962 dollars. As shown in table 19.1, the actual cost in 1968 was 1.54 cents per kilowatt-hour. If this figure is adjusted to reflect the change in the Consumer Price Index, it corresponds to approximately 1.34 cents per kilowatt-hour in terms of 1962 dollars. Between 1968 and 1971 the Consumer Price Index increased by more than 17 percent which was greater than the increase in the average cost of power during that period. Thus, as of mid-1971, the cost of power is within the cost reduction goals of the 1964 Survey.

If the future power facilities were to be built and operated under the conditions prevailing in 1962–64, it is reasonable to expect that improvements in technology would permit the downward trend to continue, at least to the projected cost level in 1980.

In recent years, however, the environmental problems besetting the nation have become more serious and the cost of protecting the environment is becoming recognized as an essential part of the cost of any product of any process that uses or infringes upon land, water, and air resources. The electric power industry is a major user of resources, and must take a leading role in environmental protection. The record of the last few years indicates that the industry is accepting this responsibility.

The cost estimates in this chapter are based on the assumption that both the power industry and the suppliers of its equipment, fuel, and other material will do whatever is necessary to provide needed power in keeping with attainable environmental protection objectives. Consequently, it is estimated that the recent reversal in the historical downward trend in the real cost of electrical service will be carried into the future, and that in spite of technological improvements, better coordination, and economies of scale, power costs to the consumer will gradually increase. This anticipated increase is attributable generally to two factors: (1) the expected increase in fixed charge rates from an industry wide average of 11.2 percent in 1968 to about 13.7 percent in 1990; and (2) the additional capital and operating costs involved in needed environmental protection features. By 1990 a significant portion of the cost of power

[1] See figure 19.1.

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TABLE 19.1

Component Costs of Power Supply

[Per Kilowatt-Hour—1968 Equivalent Dollars]

Function	Actual 1968 (cents/kWh)	Percent of Total	1990 Projected (cents/kWh)	Percent of Total	Increase (cents/kWh)
Production	0.77	50	1.09	60	0.32
Transmission	0.20	13	0.30	16	0.10
Distribution	0.57	37	0.44	24	−0.13
Total	1.54	100	1.83	100	0.29

to the consumer will be attributable to protection of the environment.

The distribution of the estimated 1990 costs among power supply functions, as compared to the 1968 cost distribution, is shown in table 19.1.

Table 19.2 shows the electric power cost that existed in 1968 and that is expected for 1990 in terms of the 1968 purchasing power of the dollar and at several illustrative rates of inflation.

The Commission is not attempting to estimate the rate of inflation that will prevail during the next 20 years. The figures in table 19.2 and in the text are intended merely to illustrate the extent that, as inflation decreases the value of the dollar, the cost of electricity to the consumer in current dollars becomes higher.

Since 1962—the base year used in the previous National Power Survey—the Consumer Price Index has increased at an annual compound rate of about three percent. Compounding the 1.83¢ per kilowatt-hour for 22 years at that rate would increase the average cost of electricity to the consumer in 1990 (in current dollars) to about 3.51¢ per kilowatt-hour. This is more than twice the average cost of electricity in 1968. If the 1.83¢ per killowatt-hour price were adjusted to reflect 22 years of compounding annually at 4 percent—the approximate rate at which steam electric plant construction costs have increased since 1968—the 1990 cost estimate would be about 4.34¢ per kilowatt-hour.

TABLE 19.2

Cost of Electricity to Ultimate Consumers 1968 and Projected 1990

	Cents per kWh	1990 Projected at Various Inflation Rates
U. S.[1] Average—1968	1.54	
—1990	1.83	1968 Equivalent Dollars
—1990	2.28	1%
—1990	3.51	3%
—1990	5.35	5%

[1] Excluding Alaska and Hawaii

Past Price and Rate Trends

Figure 19.1 depicts the actual unit prices that all ultimate consumers paid for electricity each

PRICE OF ELECTRICITY TO ULTIMATE CONSUMERS

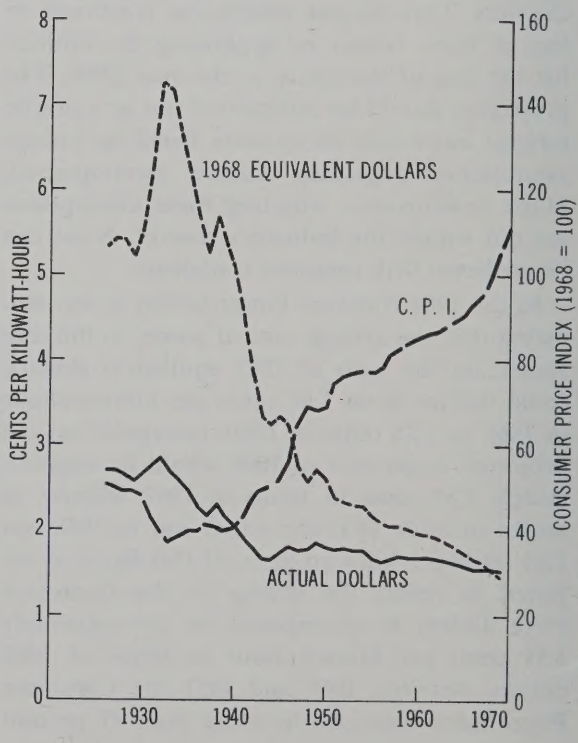

Figure 19.1

year during the 1926–69 period. The unit prices represent total electric revenues divided by total kilowatt-hours sold to consumers. Between 1926 and 1933 the price increased, and then began a sharp downward trend that continued into the early 1940's. Notwithstanding the ensuing wartime and postwar price inflation, the average price held relatively constant through the 1940's, because the inflationary effects were more than offset by improvements in power technology, economies arising from consolidating and interconnecting systems, and economies of scale accompanying the rapid growth of customer loads. The 1950's and 1960's were characterized by further inflation, and by exceedingly rapid expansion of the industry's capacity. Even so, a gradual decline in cost to the consumer continued through the 1960's.

Under the block system of rates historically employed in the United States, the average price of electricity per kilowatt-hour automatically goes down with increased usage because a greater proportion of the use is in the lower-price rate blocks. Thus, the average cost to the consumer per kilowatt-hour declined during the 1950's and 1960's because of increased consumption, partly offset by occasional rate increases, but aided at times (particularly in the early 1960's) by rate reductions.

Average costs to the customer turned upward beginning in 1969.

The electric utility industry is more slowly responsive than most industries to general inflationary pressures. At any given time, increased costs of recently installed plant and equipment are heavily diluted by investments in older plant and equipment which are generally carried in the rate base at their original cost (less depreciation). Nevertheless, inflation has had a significant effect on the price of electricity over the long run. To illustrate, the past trend of average unit prices of electricity in both "actual" and "constant" dollars is shown in figure 19.1. The adjusted price curve provides a rough measure of the change in the cost of electricity as compared with the cost of other commodities over a broad sweep of years, and dramatically demonstrates the extent to which inflation has slowed the downward trend of power costs.

The cost of producing electric power and delivering it to consumers consists of three principal components: fixed charges on the investment in facilities; fuel expenses, when applicable; and operation and maintenance expenses, excluding fuel but including allocated administrative and general expenses.

Investment in Power Facilities—1990

The cost of building power facilities of a given size and type has been rising rapidly over the past few years because of increased land, labor, and materials cost, and because of additions or modifications for environmental reasons. This upward trend is expected to continue, although it is hoped that it can be slowed substantially by the Government's program to curb inflation. Partially offsetting these facility cost rises will be the cost savings involved in the anticipated continued trend to larger generating units and higher transmission voltages, continuing improvements in technology and management, and lower unit costs of distribution facilities due to increased use per customer. In the figures that follow, however, the effects of any changes in costs after 1968 which may result from a generally higher level of wage rates and materials prices have been excluded and only those due to factors not related to general inflation, such as additional investment for environmental protection and changes in unit sizes, and other technological improvements have been included.

Generation

The estimated average unit investment costs during 1969 to 1990 for power plants of various sizes and types are shown in table 19.3. The costs for nuclear plants in table 19.3 represent estimates for light water reactors. Breeder reactors will undoubtedly comprise part of the nuclear capacity in 1990, but for purposes of this report it is assumed that their installation would not cause any substantial change in the estimated overall power costs through 1990. The figures in the table are averages for all types and all locations of plants. Costs of individual installations may vary significantly from the averages shown.

Transmission

Construction costs of overhead transmission lines are estimated to range generally from \$55,000 per circuit mile for 69 kilovolt to \$190,000 for 765 kilovolt. Substation costs are estimated at 40 percent of the total transmission

TABLE 19.3

Estimated Average Investment Cost Per Kilowatt for New Generating Capacity During the Period 1969 to 1990

[1968 Price Levels]

Unit Size Groups	NE	EC	SE	WC	SC	W
		Fossil Fuel Steam Plants [1] *$/kW*				
100 MW & less	210	210	205	210	185	200
101–300 MW	195	200	185	195	170	180
301–600 MW	175	185	170	185	160	175
601–900 MW	165	175	165	175	145	165
901–2,400 MW	160	170	160	170	135	160
		Nuclear Plants [2] *$/kW*				
300–600 MW	250	240	235	240	235	240
601–1,200 MW	240	230	225	230	225	230
1,201–1,800 MW	235	225	220	225	220	225
1,801–2,800 MW	230	220	215	220	215	220

Gas Turbine and Diesel Plants
All gas turbine installations $85/kW
All diesel installations $125/kW

Conventional Hydroelectric Plants
All new conventional hydroelectric plants $350/kW
All additions to existing hydroelectric plants $150/kW

Pumped Storage Plants
All pumped storage developments $110/kW

[1] Fossil fuel investment costs are based on the composite (coal, oil, and gas fired) estimates for each region. The composite costs include "intermediate peaking" (cycling) units in the 100 to 900 MW size range.

[2] Nuclear installations (1969 to 1990) are assumed to be light water reactors (BWR & PWR; see preceding discussion in text regarding breeders). All estimated unit costs are exclusive of nuclear fuel inventory; however, environmental protection costs have been included.

investment. Projected costs allow for the equivalent of slightly more than 1½ percent of all transmission in 1990 being placed underground at a composite average cost of about ten times the cost of overhead installations. This allowance adds about 15 percent to the total costs of an "all overhead" 1990 transmission system. It is recognized that the actual expenditures for future undergrounding must be weighed against the relative reliability and effectiveness and the costs of alternative means of power transmission and will be contingent upon the priorities which may be established over the next two decades.

Distribution

The recorded cost of distribution facilities in operation in 1968 was $517 per customer. The estimated cost of these facilities at 1968 price levels amounts to $718 per customer. Increased capacity requirements per customer, more undergrounding, and other factors are expected to increase the per customer cost to $1,200 by 1990, again at 1968 price levels.

Nuclear Fuels Inventory

The basis of determining nuclear fuel costs is different from that for fossil fuels, in that a nuclear plant requires an initial investment of about $30 per kilowatt (at 1968 price levels) for a fuel supply that will be used over a long period of time and not be entirely consumed during its cycle through the generating plant. As a result, nuclear fuels inventory is considered a capital cost and its financial carrying charges are reflected in the annual fixed charges. Amortization of the investment cost as the fuel is con-

sumed, however, is treated as a fuel expense, as explained later.

General Plant

General plant, which includes such things as transportation equipment, office space, warehouses, laboratories and research installations, and other permanent facilities associated with more than one function, is also a capital cost. The investment in general plant is estimated at about 3.5 percent of the investment in generation, transmission and distribution. The fixed charges for general plant items are calculated separately, and then allocated to those three functions.

Total Investment

Table 19.4 summarizes, by regions, the actual 1968 and projected 1990 total investment in power facilities.

Annual Fixed Charges

Annual fixed charges, one of the components of annual power costs, include the cost of money, depreciation, interim replacements, insurance, and taxes. These elements can all be related to total (gross) investment in utility plant in service (including generating, transmission, and distribution facilities) and expressed on a levelized basis as a percentage of the total investment. The percentage relationships vary with ownership segments—privately owned, Federal, municipal, and cooperatives.

Annual fixed charge rates also vary by types of equipment, primarily because of differences in service lives but also because of some differences in tax rates and other items. It is, therefore, necessary to calculate a fixed charge rate for each major type of equipment, as well as for each type of owner.

Table 19.5 is an explanation of the derivation of fixed charge rates shown in table 19.6, using as an example conventional fossil-fueled steam-electric generating equipment with a 30-year life and financed by a hypothetical entity representing the overall mix of Federal, municipal, cooperative and investor ownerships. The fixed

TABLE 19.4

Total Investment in Electric Plant—Actual 1968 and Projected 1990

[Billions of Dollars]

Region	Production Plant	Transmission Facilities	Distribution Facilities	General Plant	Nuclear Fuels Inventory	Total Electric Plant
			1968 (Actual)			
Northeast	$ 8.3	$ 3.3	$ 8.8	$ 0.6	....	$ 21.0
East Central	5.8	2.5	5.2	0.6	....	14.1
Southeast	6.7	2.7	5.6	0.4	....	15.4
West Central	5.7	2.2	5.0	0.5	....	13.4
South Central	4.0	1.9	4.7	0.5	....	11.1
West	9.0	3.8	6.6	0.7	....	20.1
U.S. Total	39.5	16.4	35.9	3.3	([1])	95.1
Percent of Total	41.6	17.2	37.7	3.5	....	100.0
			1990 (at 1968 price levels)			
Northeast	$ 40.3	$ 19.2	$ 28.1	$ 3.1	$ 3.5	$ 94.2
East Central	32.0	13.9	15.9	2.2	1.3	65.3
Southeast	45.6	15.2	17.1	2.7	2.8	83.4
West Central	29.9	13.4	18.0	2.1	2.3	65.7
South Central	33.1	11.9	19.6	2.3	1.4	68.3
West	49.6	25.7	25.7	3.5	3.0	107.5
U.S. Total	230.5	99.3	124.4	15.9	14.3	484.4
Percent of Total	47.6	20.5	25.7	3.3	2.9	100.0

[1] In 1968 nuclear fuel was leased from the Atomic Energy Commission.

TABLE 19.5

Example of Derivation of Fixed Charge Rate

Fixed Charges—30-Year Life, Conventional Steam Generating Equipment	Composite Total Industry
Cost of money	8.2%
Depreciation and replacements	1.2%
Insurance	0.2%
Income taxes	2.2%
Other taxes	2.4%
Total	14.2%

charges resulting from these analyses are used in estimating the 1990 costs of power.

Composite fixed charge rates, derived by regions for various types of equipment, are shown in table 19.6.

Fuel Cost

A major operating cost, except for conventional hydroelectric installations, is that associated with the procurement, transportation, storage, and handling of fuel. Fossil fuel costs vary significantly among regions, as shown in table 19.7. The estimated costs shown for 1990 suggest a stabilization level for fluctuating costs that may, individually and at various times, depart rather drastically from the figures shown. In the long run, however, it is assumed that fossil fuel costs will approximate those shown in the table which reflect an increase over costs prevailing in 1968 of approximately 50 percent for coal and oil and 100 percent for gas increased in each case to reflect inflation since 1968. It is also assumed that the general relationships between costs of the different fossil and nuclear fuels will remain fairly constant, but should the cost relationships vary significantly, there will be changes in the amounts of each fuel used.

For the United States, as a whole, and considering the changes in fuel mix the projected fossil fuel cost per kilowatt-hour in 1990 is 139 percent of the costs at the end of 1968 (in constant dollars and exclusive of gas turbine and diesel fuel). In the 1969–71 period, not shown separately in the table, the cost increase was approximately 25 percent (or about 40 percent in current dollars). This phenomenal recent increase was largely due to the sudden imbalances in the fuel supply-demand relations caused by the rush to obtain low-sulfur fuels to meet emerging air pollution standards. Large spot purchases were often necessary, thus losing the economies of long-term contracts. It is expected that these imbalances will tend to disappear as the increasingly stricter standards reach an equilibrium and the most economical long-range methods for meeting environmental standards emerge.

The general increase in 1990 fossil fuel costs results from higher costs of producing "cleaner" fuels and from the environmental and safety improvements in the mines and other fuel producing installations despite anticipated improvements in efficiency in the production of fuels.

Nuclear fuel burn-up costs are those costs resulting from amortization of the nuclear fuel

TABLE 19.6

Estimated 1990 Composite Annual Fixed Charge Rates

			1990 Fixed Charge Rates (Percent)					
Service Life in Years			**30**	**30**	**35**	**100**	**30–50**	**35**
Region	**General Plant**	**Nuclear Fuel** [1]	**Generation**				**Trans-mission**	**Distri-bution**
			Fossil	**Nuclear**	**GT & IC**	**Hydro**		
Northeast	14.6	12.8	15.4	15.2	14.0	9.9	14.3	14.7
East Central	14.2	13.2	14.9	15.6	12.4	14.3	14.2	13.6
Southeast	11.9	10.9	12.7	13.2	12.3	9.9	12.4	11.7
West Central	12.1	12.8	14.3	15.2	10.9	8.4	13.0	12.7
South Central	12.5	12.4	14.2	14.8	9.3	6.5	13.7	12.4
West	11.4	12.0	13.9	14.4	9.9	9.1	12.1	12.4

[1] Fixed charges for nuclear fuel do not include a provision for depreciation, which is essentially equivalent to the nuclear fuel burnup included in the operating costs.

TABLE 19.7

Fossil Fuel Costs—Actual 1968 and Projected 1990

Region	Coal		Oil		Gas		Total Fossil Fuel			
	Billion kWh	¢/Million Btu	Billion kWh	¢/Million Btu	Billion kWh	¢/Million Btu	Billion kWh	¢/Million Btu	Cost $ Million	Mills/ kWh
1968 Fossil Fuel Cost (Includes Gas Turbine & Diesel)										
Northeast	126.0	30.5	67.0	32.8	11.9	35.8	204.9	31.6	$ 692	3.38
East Central	262.2	23.0			1.5	34.0	263.7	23.0	629	2.39
Southeast	164.4	26.2	20.9	30.4	24.1	29.9	209.4	27.0	560	2.67
West Central	106.9	26.4			24.5	26.2	131.4	26.3	371	2.82
South Central	8.9	22.7			156.0	20.9	164.9	21.0	368	2.23
West	16.4	20.6	13.0	34.0	86.1	29.7	115.5	28.9	340	2.94
Total U.S.	684.8	25.5	100.9	32.8	304.1	25.1	1,089.8	26.1	$2,960	2.72
1990 Estimate of Fossil Fuel Cost (Excludes Gas Turbine & Diesel) [1]										
Northeast	98.0	45.8	92.0	49.2			190.0	47.4	$ 880	4.63
East Central	559.0	34.5	45.0	52.4			604.0	35.8	2,022	3.35
Southeast	364.0	39.3	167.0	45.6	42.0	59.8	573.0	42.6	2,309	4.03
West Central	181.0	39.6	15.0	44.4	24.0	52.4	220.0	41.3	859	3.90
South Central	265.0	34.1	45.0	35.6	286.0	41.8	596.0	37.9	2,159	3.62
West	226.0	30.9	97.0	51.0	73.0	59.4	396.0	41.1	1,555	3.93
Total U.S.	1,693.0	36.2	461.0	47.1	425.0	47.2	2,579.0	40.0	$9,784	3.79

Region	Light Oil (No. 2)		Natural Gas		Total GT & IC Fuel			
	Billion kWh	$/Million Btu	Billion kWh	$/Million Btu	Billion kWh	$/Million Btu	Cost $ Million	Mills/ kWh
1990 Estimate of Gas Turbine & Diesel Fuel Cost [1]								
Northeast	9.0	1.26			9.0	1.26	$190	21.11
East Central	8.0	1.13			8.0	1.13	152	19.00
Southeast	6.0	1.23	3.0	0.60	9.0	1.02	155	17.22
West Central	4.5	1.20	4.5	0.52	9.0	0.86	130	14.44
South Central	2.2	0.94	6.8	0.42	9.0	0.55	83	9.22
West	3.8	1.06	1.2	0.59	5.0	0.95	80	16.00
Total U.S.	33.5	1.17	15.5	0.50	49.0	0.96	$790	16.12

[1] 1990 regional fuel costs (shown at 1968 dollar values) are increased 50 percent above 1968 fuel costs for coal and oil and 100% for gas. The 1990 total fuel cost for each region is based on the estimated composite heat rate for all fuels burned in the region.

investment, not including financial carrying charges on that investment. Such costs are expected to remain relatively consistent among regions and it is estimated that they will average 1.6 mills per kilowatt-hour (at 1968 price levels) for all regions in 1990.

Fuel costs for each region are applied to the anticipated pumping loads for pumped storage projects in that region to get total fuel costs. (See table 19.11)

Table 19.8 summarizes fuel costs for all types of generation for the years 1968 and 1990.

Operation and Maintenance Costs

Operation and maintenance costs other than fuel burn-up include the payrolls of personnel, supervision and engineering expenses, supplies and equipment, and related items.

Annual operation and maintenance costs of transmission facilities in 1990 are expected to be

TABLE 19.8

1968 and 1990 Fuel Costs for all Types of Generation

	1968			1990		
	Billion kWh	Fuel Cost $ Million	Fuel Cost Mills/kWh	Billion kWh	Fuel Cost $ Million	Fuel Cost Mills/kWh
				(at 1968 price levels)		
Fossil steam	1,090	2,960	2.72	2,579	9,784	3.79
Gas turbine & IC	([1])	([1])	([1])	49	790	16.12
Nuclear steam	12	([2])		2,913	4,661	1.60
Conventional hydro	218	(no fuel cost)		319	(no fuel cost)	
Pumped storage hydro	4	([3])	([3])	62	([3])	([3])
Gross values	1,324	2,960	2.24	5,922	15,235	2.57
Less pumping energy	6			94		
Energy at busbar	1,318			5,828		
Adjustments [4]	120			501		
Energy and fuel cost at consumption level	1,198	2,960	2.47	5,327	15,235	2.86

[1] The generation and associated fuel cost for GT & IC are included in the 1968 fossil steam figures. The 1968 estimates for GT & IC are 7 billion kWh generation and $47 million fuel.

[2] The nuclear fuel cost for 1968 is not included because reported figures apparently do not represent nuclear fuel burn-up; the cost has been estimated at $26 million.

[3] Fuel costs for pumping are included in fossil and nuclear steam plant costs, as appropriate.

[4] Losses, import-export differences, and other.

about 1.8 percent of the total investment in transmission lines and substations which is approximately the current rate.

Distribution system operation and maintenance costs, estimated on the basis of cost per customer, are expected to increase from a national average of $32 per customer in 1968 to about $46 per customer in 1990. The increase stems in part from the higher operation and maintenance cost for underground lines and the increased costs of minimizing environmental effects of distribution systems, and in part from the cost of additional facilities required for increasing use per customer. However, since use per customer is expected to triple by 1990, the cost per kilowatt-hour of distribution operation and maintenance in constant dollars should decrease from 1.6 to 0.9 mills.

Operation and maintenance costs, except fuel, for generating plants are generally related to kilowatts of installed capacity, and they vary from region to region. Table 19.9 summarizes estimates of 1990 costs by type of facility for normally expected capacity factors.

Administrative and General Expenses

Administrative and general expenses include administrative and general salaries and related expenses, legal and regulatory expenses, payments for outside services employed, injuries

TABLE 19.9

Estimated Average 1990 Operation and Maintenance Costs of Generating Plants, Exclusive of Fuel Costs—1968 Price Levels

Type of Generation	Annual Cost Dollars/kW
Fossil steam	[1] 3.10
Nuclear steam	3.00
Gas turbine	[2] 1.50
Diesel	4.50
Conventional hydro	[3] 2.65
Pumped storage	1.35

[1] Varies among regions from $2.75 to $3.50.

[2] Varies among regions to as high as $3.50.

[3] Varies among regions from $2.00 to $4.50.

and damages, welfare and pensions, and other miscellaneous expenses. Such expenses are expected to increase in future years, primarily to provide increased pension fund contributions and other fringe benefits, and to meet the research and development needs outlined in chapter 21. The estimates of administrative and general expenses have been increased from the historical average of about 25 percent of operation and maintenance expenditures, exclusive of fuel, to about 33 percent for 1990. These expenses were then prorated to the functions of production, transmission, and distribution on the basis of projected operation and maintenance payroll costs.

Working Capital

Working capital is required to meet current expenses pending collection of revenues. Working capital requirements include cash, prepayments, materials and supplies, and fuel stocks other than nuclear fuel. The 1968 working capital maintained by Class A & B privately owned utilities was 3.38 percent of the gross investment of those utilities and the average for the entire industry was somewhat less. In 1968, approximately one-half of the total working capital was for fossil fuel inventory (primarily coal). Since the proportion of fossil fueled generation will be considerably less in 1990 it is believed that about 3.25 percent of the investment would provide sufficient working capital in that year. Thus, the 1990 working capital requirement is estimated to be 3.25 percent of $484.4 billion, or nearly $15.75 billion. The total annual cost of working capital in 1990 is estimated by multiplying the 1990 estimated working capital requirements by 10.65 percent (8.2 percent estimated cost of money + 2.2 percent for income tax + 0.25 percent for incidental taxes, depreciation, depletion, and insurance on materials and supplies). The resulting $1,675 million is allocated 60 percent to production, 15 percent to transmission and 25 percent to distribution.[2] The allocation to these functions by regions is shown in table 19.10.

Total Power Costs

Power costs for 1968 and projections for 1990 are shown in table 19.11 by regions and United States total.

The total annual costs of power for 1990 are estimated to be more than five times the 1968 costs—an increase from $18,484 million to $97,200 million. However, sales are expected to increase nearly 4.5 times—from 1,198 billion kWh in 1968 to 5,327 billion kWh in 1990; and use per customer (average for residential, commercial, industrial, and all other customers) is expected to triple from 17,300 to 52,200 kilowatt-hours per year. Average costs per kilowatt-hour,

[2] In table 19.1 the share of total cost distribution to each function is: production, 60%; transmission, 16%; distribution, 24%.

TABLE 19.10

Estimated 1990 Annual Cost of Working Capital

[1968 Dollars]

Region	Production [1] (million)	Transmission [2] (million)	Distribution [3] (million)	Totals (million)
Northeast	$ 169	$ 48	$ 99	$ 316
East Central	194	36	63	293
Southeast	208	39	60	307
West Central	99	33	55	187
South Central	158	30	63	251
West	172	64	85	321
Total U. S.	$1,000	$250	$425	$1,675

[1] Production working capital is allocated among regions generally on the basis of the estimated 1990 generation, with fossil plants allocated at twice the unit rate applied to other plants.

[2] Transmission working capital is allocated on the basis of the estimated 1990 transmission plant investment in each region.

[3] Distribution working capital is allocated on the basis of the 1990 estimated number of customers in each region.

TABLE 19.11

Costs of Electricity by Regions—1968 Actual and 1990 Projected

	Northeast		East Central		Southeast		West Central		South Central		West		Total U.S.	
	$ Million	Mills/ kWh	$ Million	Mills/ kWh	$ Million	Mills/ kWh	$ Million	Mills/ kWh	$ Million	Mills/ kWh	$ Million	Mills/ kWh	$ Million	Mills/ kWh
1968														
Power Production Costs														
Fuel	692	3.04	629	2.84	560	2.48	371	2.69	368	2.48	340	1.43	2,960	2.47
Other O & M	330	1.45	307	1.39	284	1.26	225	1.63	186	1.26	277	1.17	1,609	1.34
Allocated Admin. & Gen'l.	70	0.31	47	0.21	44	0.19	40	0.29	38	0.26	39	0.16	278	0.23
Fixed Charges	1,022	4.48	743	3.36	624	2.76	633	4.59	462	3.12	959	4.05	4,443	3.71
Total Production Costs	2,114	9.28	1,726	7.80	1,512	6.69	1,269	9.20	1,054	7.12	1,615	6.81	9,290	7.75
Transmission Costs														
O & M Expenses	59	0.26	46	0.21	48	0.21	40	0.29	34	0.23	68	0.29	295	0.25
Allocated Admin. & Gen'l.	17	0.07	13	0.06	14	0.06	12	0.09	10	0.07	20	0.08	86	0.07
Fixed Charges	440	1.93	360	1.62	291	1.29	260	1.88	254	1.71	390	1.65	1,995	1.66
Total Transmission Costs	516	2.26	419	1.89	353	1.56	312	2.26	298	2.01	478	2.02	2,376	1.98
Distribution Costs														
O & M Expenses	502	2.20	327	1.48	292	1.29	262	1.90	231	1.56	349	1.47	1,963	1.64
Allocated Admin. & Gen'l.	147	0.64	98	0.44	93	0.41	85	0.62	80	0.54	82	0.35	585	0.49
Fixed Charges	1,109	4.87	635	2.87	623	2.76	580	4.20	535	3.62	788	3.32	4,270	3.56
Total Distribution Costs	1,758	7.71	1,060	4.79	1,008	4.46	927	6.72	846	5.72	1,219	5.14	6,818	5.69
Total Cost of Power	4,388	19.25	3,205	14.48	2,873	12.71	2,508	18.18	2,198	14.85	3,312	13.97	18,484	15.42
Sales—Billion kWh	227.9		221.3		226.1		138.0		148.0		237.1		1,198.4	
Total No. Customers—Millions	16.8		11.3		11.1		9.7		8.2		12.3		69.4	
1990 (1968 Dollar Values)														
Power Production Costs														
Fuel	2,176	2.60	2,599	3.22	3,407	3.09	1,720	2.67	2,706	3.27	2,627	2.37	15,235	2.86
Other O & M	619	0.74	577	0.71	768	0.70	481	0.75	597	0.72	744	0.67	3,786	0.71
Allocated Admin. & Gen'l.	223	0.27	208	0.26	276	0.25	183	0.28	215	0.26	268	0.24	1,373	0.26
Fixed Charges	7,101	8.48	5,581	6.91	6,763	6.14	5,065	7.85	5,291	6.39	7,467	6.74	37,268	7.00
Total Production Costs	10,119	12.09	8,965	11.10	11,214	10.18	7,449	11.55	8,809	10.64	11,106	10.02	57,662	10.83
Transmission Costs														
O & M Expenses	346	0.42	250	0.31	273	0.25	241	0.37	214	0.26	463	0.42	1,787	0.33
Allocated Admin. & Gen'l.	100	0.12	73	0.09	79	0.07	70	0.11	62	0.07	134	0.12	518	0.10
Fixed Charges	2,864	3.42	2,053	2.54	1,970	1.79	1,814	2.81	1,703	2.06	3,236	2.92	13,640	2.56
Total Transmission Costs	3,310	3.96	2,376	2.94	2,322	2.11	2,125	3.29	1,979	2.39	3,833	3.46	15,945	2.99
Distribution Costs														
O & M Expenses	1,133	1.35	722	0.89	610	0.55	632	0.98	659	0.80	968	0.87	4,724	0.89
Allocated Admin. & Gen'l	362	0.43	231	0.29	195	0.18	226	0.35	211	0.25	310	0.28	1,535	0.29
Fixed Charges	4,392	5.25	2,333	2.89	2,177	1.98	2,432	3.77	2,589	3.12	3,411	3.08	17,334	3.25
Total Distribution Costs	5,887	7.03	3,286	4.07	2,982	2.71	3,290	5.10	3,459	4.17	4,689	4.23	23,593	4.43
Total Cost of Power	19,316	23.08	14,627	18.11	16,518	15.00	12,864	19.94	14,247	17.20	19,628	17.71	97,200	18.25
Sales—Billion kWh	836.7		807.8		1,101.1		645.2		828.2		1,108.1		5,327.1	
Total No. Customers—Millions	23.5		15.2		14.5		13.3		15.1		20.4		102.0	

in terms of 1968 prices, are therefore projected to increase from 1.54 to 1.83 cents per kilowatt hour.

Historically, there have been significant differences among regions in the cost of power to the consumer. These differences have reflected such factors as the amount of fuel-free hydro capacity available, the relative cost of fossil fuels, labor costs, the composition of system ownership, and the degree of coordination that enhances the opportunities for economies of scale. Such differences are expected to continue. In 1968, when the average cost, nationally, was 1.54 cents per kilowatt-hour, regional costs ranged from 1.3 to 1.9 cents. Table 19.11 projects regional costs ranging from 1.5 to 2.3 cents per kilowatt-hour, based on 1968 price levels. These relationships are shown graphically in figure 19.2.

ELECTRIC POWER COSTS
1968 AND 1990
CENTS PER KWH (1968 DOLLARS)

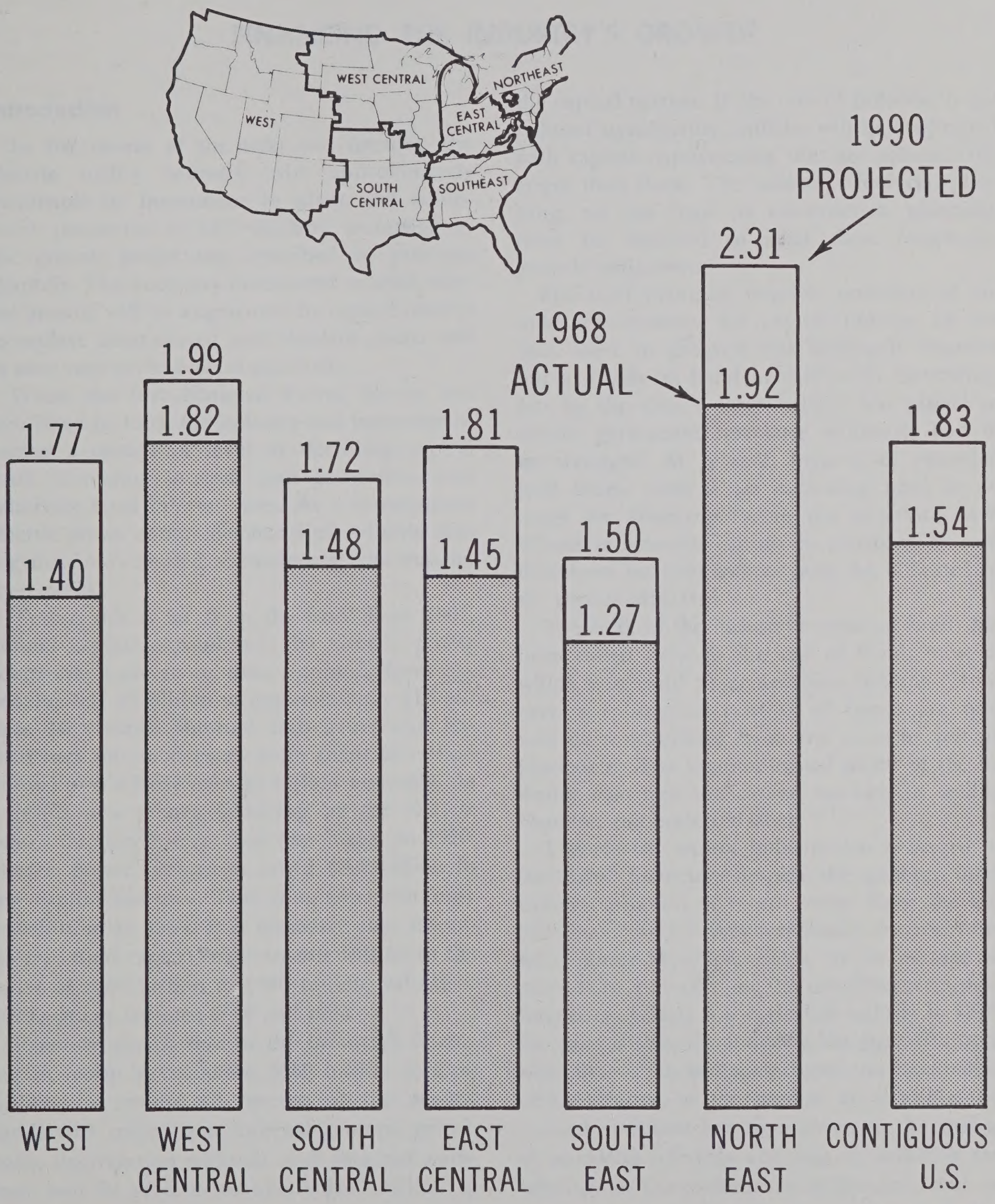

Figure 19.2

CHAPTER 20

FINANCING THE INDUSTRY'S GROWTH

Introduction

In the course of the next two decades, the electric utility industry will approximately quadruple its investment in plant and equipment (measured in 1970 dollars) according to the growth projections described in previous chapters. The necessary investment to serve market growth will be augmented by capital outlays to replace deteriorated and obsolete plants and to meet new environmetal standards.

When the first National Power Survey was published in 1964, the industry had been experiencing a decade of level or declining capital costs, increasing internal cash generation, and relatively level interest rates. As a consequence electric power companies had little trouble raising the funds needed to modernize and expand their plant.

Today, this is far from the case. Since 1964, annual capital expenditures by electric power companies have more than doubled, from approximately $5 billion to approximately $13 billion. Meanwhile, internal cash generation has increased only moderately from about $2 billion annually to a little over $3 billion annually. As a result new money financing by the electric power industry has reached new highs. In 1970, electric power companies raised $8.2 billion in the capital markets. This compares with only $4.9 billion in 1969. It is estimated that the industry's total capital requirements will be in the order of $400 billion to $500 billion, valued at 1970's prices, between 1970 and 1990.

Based on the pattern of the industry's financing in recent years, about $160 billion to $200 billion, or around 40 percent of the needed funds will come from internal sources, principally depreciation accruals and retained earnings, and 60 percent, or about $240 billion to $300 billion, must be obtained competitively in the capital market. If the rate of inflation is not reduced significantly, utilities will be confronted with capital requirements that are substantially larger than these. The industry's financial planning, no less than its construction planning, must be designed to meet these long-range growth projections.

Financial planning requires estimates of annual requirements for capital outlays. In the past, work in progress was ordinarily financed out of funds on hand or short-term borrowing, but by the time a large project was placed in service permanent financing ordinarily had to be arranged. At present, because of extended lead times, there is an increasing need to arrange for financing before the in-service date. Whatever amounts cannot be provided by cash flow from internal sources must be obtained in the capital markets.

The bulk of the industry's external funds has been raised through the sale of bonds most of which were sold at competitive bidding. However, a substantial portion of bonds are now sold on a negotiated basis and some by private placement. The investor-owned sector of the industry also taps the capital markets by selling common and preferred stock.

The electric utility industry has a record of successful financing despite the general inflationary situation of recent years. Since the last National Power Survey was issued, interest rates have almost doubled, rising to an average of more than 8 percent for the new long term debt financing of Class A & B electric utilities in 1970. In spite of this, the industry has generally been able to attract necessary funds on reasonable terms relative to the market as a whole. Increased attention has been given to the timing of securities offerings and also to tailoring the offerings to the preferences of investors, and on occasion a planned sale has been postponed. For

the most part, financing problems have been met without delaying construction programs. This has been largely because of the industry's generally sound capital structure and its history of technological progress and steady earnings growth.

The future ability of the industry to finance its growing requirements for new capital on schedule and on acceptable terms will depend largely on how well it will be able to compete with other borrowers of capital. Since cost savings generated by rising productivity of labor and capital are generally associated with market growth and higher earnings levels, those firms and industries which are in the forefront of technological progress are likely to find that they are best able to attract and retain wide investor interest. The investment community places a premium on managerial performance measured by earnings results and demonstrated success in long-range planning.

The electric utility industry in the past has had a high standing in the investment community, and has been a leading issuer of securities for many years. The challenges to utility management in the period ahead, however, may be more formidable than in the past for many reasons, including the prospective scale of new financing and the likelihood of heavy demands for capital from other industrial sectors and from government. In addition, the industry faces a growing volume of maturing securities, generally at low interest rates, which will need to be refinanced at much higher interest rates within the next few years.

Trend of Capital Outlays

In recent years the capital requirements of the electric utility industry have been increasing rapidly to keep pace with the growth of electricity demand and higher costs associated with inflation and other requirements such as environmental control. As shown in table 20.1, the industry raised its capital expenditures to $9.6 billion in 1968, $11.1 billion in 1969, and approximately $13.0 billion in 1970, compared with capital expenditures of about $5 billion annually during the first half of the 1960's. The prospect is for a generally rising trend of capital outlays to about a $20 billion annual level before the end of the current decade and a $40 billion level by about 1990. Further price inflation will increase these amounts.

As illustrated in figure 20.1, the absence of growth in total capital expenditures by the electric utility industry from 1958 to 1965 can be traced to the sharp decline and slow recovery of new investment in fossil fuel generating stations. Generating plant investment since 1965 has been the fastest growing component of the industry's capital spending program, although there also has been a marked acceleration of investment in transmission and distribution.

Figure 20.1 also shows that the industry's annual expenditures for nuclear power facilities (excluding subsidies) amounted to almost $500 million in 1967, the first year of separate reporting, and increased to around $2,200 million by 1970. This growth in outlays for nuclear generation followed a bunching of orders for nuclear plants in 1966 and 1967, as discussed in chapter 6.

The trend of annual investment outlays by ownership sectors is illustrated in figure 20.2 for the period starting in 1953. A ratio scale is used in the chart in order to compare the relative rates of fluctuations. The outlays of the Federal and municipal sectors generally exhibit larger year-to-year variations than those of the other two sectors. It is notable also that the capital outlays of cooperative systems were higher in 1953 and 1954 than in any subsequent year before 1968. Annual outlays by Federal systems did not recover to the 1953 level until 1967, while municipal system outlays peaked in 1960 and again in 1967 and have exceeded the previous year's outlays in 1968, 1969, and 1970. The broad trend over the period has been toward a larger share of total expenditures for electric plant by investor-owned systems. The investor-owned systems' share moved up from the 70–72 percent range during the 1950's to 81 percent in 1970.

Sources of Financing for Investor-Owned Systems

Investor-owned electric utilities rely upon internal and external sources of financing in varying proportions, depending largely on the amount of capital expenditures as related to the availability of internal funds. (See tables 20.2 and 20.3.) The generation of internal funds tends to grow at a steady rate. In a period of

TABLE 20.1

Electric Utility Industry Capital Expenditures, Contiguous United States

[In Millions of Dollars]

	Generation	Transmission	Distribution	Miscellaneous	Total (partial coverage) [1]	Total (full coverage)
1948	1,103	400	1,075	84	2,662	3,000
1949	1,410	400	1,190	93	3,093	3,500
1950	1,275	425	1,127	109	2,936	3,300
1951	1,344	504	1,089	131	3,068	3,500
1952	1,925	577	1,118	118	3,738	4,300
1953	2,088	647	1,200	127	4,062	4,700
1954	1,939	666	1,288	122	4,015	4,700
1955	1,548	571	1,343	161	3,623	4,300
1956	1,479	598	1,518	186	3,781	4,400
1957	2,234	747	1,566	199	4,746	5,500
1958	2,582	764	1,373	187	4,906	5,600
1959	2,369	708	1,413	180	4,669	5,300
1960	2,226	715	1,565	183	4,690	5,300
1961	2,114	764	1,550	180	4,608	5,200
1962	1,693	792	1,593	193	4,271	4,700
1963	1,721	837	1,568	230	4,357	4,800
1964	1,814	1,047	1,688	252	4,801	5,200
1965	1,941	1,181	1,861	269	5,254	5,700
1966	2,519	1,418	2,008	302	6,345	7,000
1967	3,490	1,614	2,347	338	7,785	8,300
1968	4,255	1,899	2,564	383	9,100	9,600
1969	5,295	1,998	2,872	389	10,554	11,100
1970	6,646	2,291	3,119	506	12,562	13,000

[1] Figures may not add due to rounding.

rapidly rising capital outlays, therefore, the utilities must necessarily resort to increasingly larger proportions of external financing. When annual capital outlays more than doubled between 1965 and 1970, the proportion of outside financing increased from $1.8 billion, or 44 percent of total sources, to $7.8 billion or 70.5 percent of total sources. On the other hand, when capital outlays declined, as they did from 1958, to 1962, the utilities reduced their reliance on outside financing from $2.3 billion, or 59 percent of total sources, to $1.4 billion or 41 percent of total sources. In view of the projected growth of investment in the period ahead, it seems likely that investor-owned utilities will need to raise at least 60 percent, and perhaps as much as two thirds or more, of their capital requirements through the sale of debt and equity securities.

Table 20.3 shows that since 1946 debt financing has been the most important single source of capital and that charges for depreciation and amortization has ranked second, although for a brief period from 1961 to 1965 the relative positions of the two sources were reversed. Since 1965, these two sources combined have provided 66 to 75 percent of each year's total capital requirements. Through 1969 the remaining sources, listed in declining order of importance, were retained earnings, sales of common stock, sales of preferred stock, and accruals for deferred taxes. In 1970, however, sales of common stock and sales of preferred stock each exceeded retained earnings.

Internal Sources

The cash flow from depreciation and amortization is the most dependable of the several internal sources of funds. These "capital consumption allowances" are included in the rates charged for electric service in order to provide for the recovery of invested capital over the useful life of each class of assets.

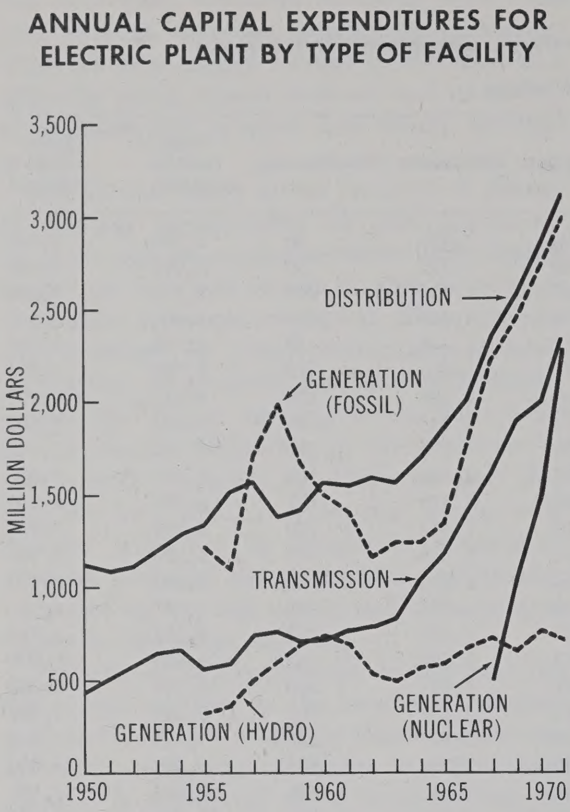

Figure 20.1

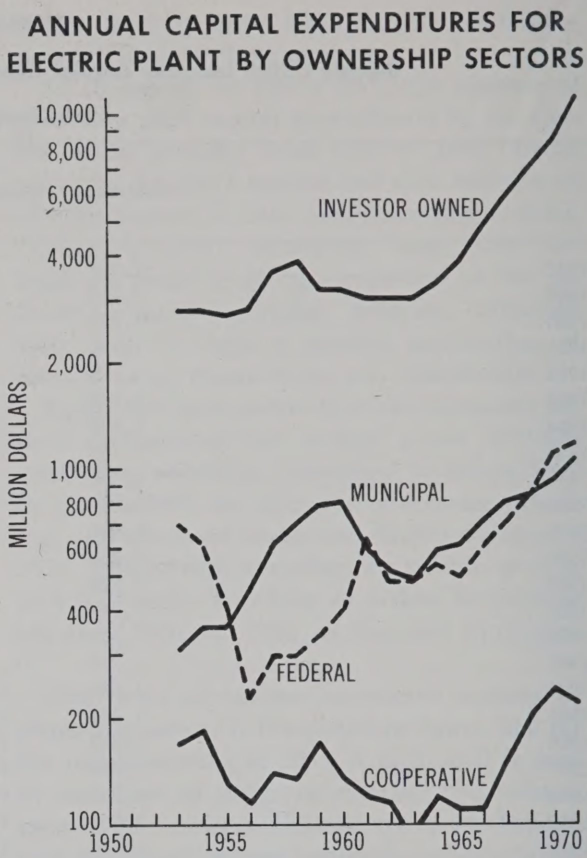

Figure 20.2

Depreciation

In a growing company, each year's capital outlays include the purchase of added capacity as well as expenditures for replacing worn-out facilities. To the extent that the gross outlay exceeds the annual charges for depreciation and other internal sources of funds, new capital funds will be required. The new investment added to the company's plant accounts will be recovered through larger depreciation deductions in future years. Also, in an inflationary economy replacement of facilities which are no longer useful with new facilities similar in size and type may create an additional capital requirement, since the replacement cost may exceed the cost of the old facilities. In the past, however, technological advances and economies of scale typically have offset the rate of inflation so that the cost of the new replacement facilities in terms of dollars per unit of output has often been lower than the unit cost associated with the facilities replaced.

Since the effects of inflation on the cost of new plant and equipment have been largely offset until recently by advancing productivity, the financing requirements of the electric utility industry, like those of most other industries, have arisen principally from the need for additional capacity. In recent years, however, productivity gains have not been sufficient to offset rapidly inflating costs.

Depreciation rates applicable to given types of property are substantially the same among electric utility companies. Such rates have tended to change only slowly over long periods of time. As shown in table 20.4, the average rates for broad asset classes ranged between 1.6 percent and 3.7 percent per year as of 1966, while the composite rate was 2.8 percent. These rates are low in comparison with those in most other industries

TABLE 20.2

Investor-Owned Electric Utilities, Sources of Funds, 1946–1970

[Millions of Dollars]

Year	External Funds				Internal Funds			
	Common Stock	Preferred Stock	Debt	Total	Retained Earnings	Deferred Taxes	Depreciation and Amortization	Total
1946	$112	$ (41)	$ 26	$ 97	$ 67	....	$ 360	$ 428
1947	162	91	556	811	54	....	376	430
1948	294	56	1,182	1,533	147	....	403	550
1949	432	213	797	1,443	161	....	431	592
1950	472	182	632	1,287	148	....	483	632
1951	436	156	919	1,512	98	....	525	623
1952	717	165	789	1,673	200	....	562	762
1953	304	187	1,254	1,746	223	....	618	841
1954	516	196	1,229	1,942	182	$132	692	1,007
1955	415	180	1,080	1,676	140	128	766	1,035
1956	415	224	1,051	1,691	222	221	844	1,289
1957	541	87	1,932	2,561	304	221	906	1,432
1958	551	248	1,450	2,250	323	225	994	1,543
1959	715	92	1,247	2,054	313	237	1,093	1,645
1960	540	164	1,226	1,931	379	167	1,181	1,729
1961	565	68	996	1,630	275	170	1,283	1,729
1962	462	148	764	1,375	469	130	1,384	1,984
1963	732	15	829	1,577	159	110	1,489	1,759
1964	661	43	1,008	1,713	501	42	1,574	2,119
1965	379	142	1,261	1,784	570	49	1,675	2,294
1966	287	340	2,411	3,039	694	43	1,774	2,512
1967	523	465	2,630	3,618	591	57	1,894	2,542
1968	623	476	3,161	4,260	745	62	2,034	2,841
1969	864	401	3,552	4,817	866	97	2,203	3,166
1970	1,795	1,117	4,866	7,778	755	111	2,399	3,265

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States.*

reflecting the relatively long service life of electric utility assets. Even these low rates, however, generate a large cash flow—about 11 percent of electric operating revenues—since the industry is among the most capital-intensive in the United States economy. Table 20.4 also suggests a gradual shift toward higher depreciation rates in recent years.

Retained Earnings

Retained earnings are another major internal source of financing amounting to $755 million in 1970 or 6.8 percent of the total sources of funds in that year. They represent earnings that are "plowed back" into the business rather than paid out as dividends on common stock. Retained earnings in the order of 30 percent of total earnings for the electric power industry may be compared with an average of more than 50 percent for all corporate enterprises. During the 1960's retained earnings have provided a somewhat larger share of the financing requirements of investor-owned utilities than during the 1950's, both because the earned rate of return on equity capital increased during this period (see table 20.9) and because the proportion of total earnings retained increased by about 5 percentage points. In 1970, however, the earned rate of return on equity capital and the proportion of total earnings retained both decreased.

The industry's decision to reinvest a higher portion of each year's earnings is partly influ-

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TABLE 20.3

Investor-Owned Electric Utilities, Sources of Funds in Percent, 1946–1970

Year	External Funds				Internal Funds			
	Common Stock	Preferred Stock	Debt	Total	Retained Earnings	Deferred Taxes	Depreciation and Amortization	Total
1946	21.4	(7.9)	5.1	18.6	12.9	....	68.5	81.4
1947	13.1	7.4	44.8	65.3	4.4	....	30.3	34.7
1948	14.2	2.7	56.7	73.6	7.1	....	19.3	26.4
1949	21.2	10.5	39.2	70.9	7.9	....	21.2	29.1
1950	24.6	9.5	33.0	67.1	7.8	....	25.1	32.9
1951	20.4	7.3	43.1	70.8	4.6	....	24.6	29.2
1952	29.4	6.8	32.5	68.7	8.2	....	23.1	31.3
1953	11.8	7.2	48.5	67.5	8.6	....	23.9	32.5
1954	17.5	6.7	41.6	65.8	6.2	4.5	23.5	34.2
1955	15.3	6.7	39.8	61.8	5.2	4.7	28.3	38.2
1956	13.9	7.5	35.3	56.7	7.5	7.4	28.4	43.3
1957	13.6	2.2	48.3	64.1	7.6	5.5	22.8	35.9
1958	14.5	6.6	38.2	59.3	8.6	5.9	26.2	40.7
1959	19.3	2.5	33.7	55.5	8.5	6.4	29.6	44.5
1960	14.7	4.5	33.5	52.7	10.4	4.6	32.3	47.3
1961	17.0	2.1	29.0	48.1	8.3	5.1	38.5	51.9
1962	13.8	4.4	22.7	40.9	14.0	3.9	41.2	59.1
1963	22.0	0.5	24.8	47.3	4.8	3.3	44.6	52.7
1964	17.3	1.1	26.3	44.7	13.1	1.1	41.1	55.3
1965	9.3	3.5	30.9	43.7	14.0	1.2	41.1	56.3
1966	5.2	6.1	43.4	54.7	12.5	0.8	32.0	45.3
1967	8.5	7.5	42.7	58.7	9.6	0.9	30.8	41.3
1968	8.8	6.7	44.5	60.0	10.5	0.9	28.6	40.0
1969	10.8	5.0	44.5	60.3	10.8	1.2	27.6	39.7
1970	16.3	10.1	44.1	70.4	6.8	1.0	21.7	29.6

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States.*

enced by the preferences of equity investors. In recent years these preferences appear to give relatively greater weight to future returns, which are closely related to the degree of earnings retention, than to present returns in the form of dividend receipts. Moreover, income taxes are weighted on the side of earnings retention, because of the preferential rate on capital gains and the advantage of postponing individual income tax payments. Another reason for earnings retention is that it serves the same purpose as new stock sales in maintaining the desired level of equity in a company's capital structure, without the trouble and expense of issuing new equity securities.

Deferred Taxes

Deferred taxes as a source of internal financing has declined both in relative and absolute terms over the past 10 years as shown in table 20.3. Since 1964, deferred taxes have provided about one percent of the industry's financing requirements, whereas in several earlier years they provided 5 percent or more.

External Sources

Nonfinancial corporations typically resort to external sources for only one-fourth to one-third of their financing needs. In contrast to this, the investor-owned electric utilities in recent years

TABLE 20.4

Average Rates of Depreciation for Investor-Owned Electric Utilities by Functional Plant Classification for Selected Years (Percent)

Plant Classification	1948	1949	1951	1958	1961	1966
Production:						
Steam Production	2.5	2.6	2.5	2.5	2.7	2.8
Hydraulic Production	1.3	1.4	1.4	1.2	1.5	1.6
Other Production	3.7	4.7	3.7	3.8	3.3	3.7
Transmission	2.5	2.5	2.5	2.3	2.4	2.4
Distribution	2.8	2.9	2.8	2.9	2.8	3.1
General [1]	3.6	4.3	4.4	4.6	4.3	3.7
Composite	2.5	2.6	2.6	2.6	2.7	2.8

[1] Excludes transportation equipment for year 1966 only.

Source: Federal Power Commission, *Electric Utility Depreciation Practices*, various years.

have raised more than half of their cash requirements by outside financing. Utility sales of bonds have been especially heavy during the last five years, a time when other industries were also borrowing in large amounts and when interest rates in the United States advanced to the highest levels in more than 100 years. In 1970 the investor-owned utilities raised $4.9 billion, or 44 percent of their cash requirements, through bond sales and about $2.9 billion, or 26 percent, through sales of preferred and common stocks. In 1970 utility bonds constituted approximately 27 percent of the total registered with the Securities and Exchange Commission for all corporations.[1]

In the recent upsurge of long term corporate borrowing, state and local government pension funds and insurance companies have been among the largest suppliers of funds. Mutual savings banks and individual investors, two groups which were net sellers during the first half of the 1960's, were attracted by the higher yields being offered, and entered the market on a fairly large scale after 1965. Individual investors were also attracted, in some cases, by mortgage bonds and debentures with shorter maturities. The electric utilities, as well as other corporate borrowers, benefited from this broadening of the market for bond offerings although they suffered some loss of traditional sources. In the second half of the 1960's private pension funds invested a greater proportion of newly available funds in equities instead of debt securities. Whether this traditional source of funds will return in strength to the debt markets in the 1970's remains to be seen.

In the face of high interest rates and a generally tight capital market during the past three or four years, some corporate borrowers, including electric utilities, have substituted short-term for long-term financing at generally lower interest rates. Although few utilities had used the commercial paper market in the past, some decided to minimize long term commitments at current market rates by turning to this source of financing. The number of companies electing these essentially new departures in utility financing increased substantially during 1969 and 1970. Table 20.5 shows the recent growth of short-term borrowing by electric utilities through instruments of not more than one year's maturity. The increases since 1965 reflect larger amounts of construction work as well as conditions in the financial markets.

The electric utilities also raise a portion of their external funds through sales of preferred stock. (See table 20.3). Indeed, the electric utilities group ranks as the largest issuer of preferred stock, although the popularity of this form of financing by utilities appears to be lower today than in years past.[2] Preferred stock

[1] Securities and Exchange Commission, *Statistical Bulletin*, March 1971.

[2] In 1970, however, sales of preferred stock increased sharply to nearly three times the 1969 level.

TABLE 20.5

Short-Term Borrowing by Private Electric Utilities 1960–1970

Year	Short-Term Debt at Year End ($ millions)	Total Debt at Year End ($ millions)	Short-Term Debt as Percent of Total Debt
1960.....	505	21,540	2.34
1961.....	477	22,506	2.12
1962.....	358	23,270	1.54
1963.....	467	24,099	1.94
1964.....	519	25,108	2.07
1965.....	867	26,370	3.29
1966.....	1,053	28,781	3.66
1967.....	1,480	31,839	4.65
1968.....	1,961	35,480	5.53
1969.....	2,806	39,877	7.04
1970.....	2,702	44,639	6.05

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States.*

has some similarity to bonds in that its dividends are payable at a fixed rate, but preferred stock does not have maturity dates and the issuers generally have no contractual obligation to pay dividends, except in preference to dividends on common stock. Utilities have issued both convertible and non-convertible preferred stock but they have favored the latter. Between $300 million and $1.1 billion have been raised annually through preferred stock issues in recent years. These sums accounted for 5 to 10 percent of the industry's total financing needs during 1966–1970.

The sale of common stock is the remaining source of external financing available to investor-owned utilities. Over the long run this source has declined in relative importance, from an average of 18 percent of total financing requirements during the 1950's to 13 percent [3] during the 1960's. Much of this decline was offset by increased financing through earnings retention. With the onset of the general stock market decline beginning in 1965, utility stock prices experienced a less favorable rate of appreciation. As a consequence it became relatively less attractive to finance through the use of common equity. As debt financing tended to replace common equity financing, the common equity portion of total capitalization declined to 35.4 percent at the end of 1970, after reaching 39.0 percent at the end of 1965.

Apart from the immediate state of the securities markets, the chief influence on decisions concerning the type of financing to use is the need to maintain a suitably balanced capital structure and adequate interest coverage in order to continue to raise new capital at reasonable cost. Debt capital has usually been considered to be the least costly method of financing and common equity capital the most costly. However, the capital market will not permit unlimited substitution of debt for equity, despite the tax advantages associated with debt financing. The attraction of bond financing from a cost standpoint rests upon (1) the existence of a cushion of equity earnings adequate to provide a margin of safety so that payment of bond interest is assured through adequate "interest coverage" and (2) a cushion of equity capital to reduce the risk of capital loss to bondholders in the event of foreclosure. The greater the reliance on bond financing, the narrower is the risk protection afforded to bondholders and the greater the exposure of equity investors to fluctuations in earnings. Increased risks usually lead to higher costs of capital as well as to restriction of options for future financing. A mix of financing which maintains a balanced capital structure is therefore considered essential for minimizing a company's overall cost of capital and safeguarding its access to the capital markets when new financing is necessary.

Although each company acts from the standpoint of its own financial circumstances, there is a high degree of similarity in the capital structures of the investor-owned utilities. Among 197 Class A and B electric companies, there were 113 with debt ratios falling between 50 percent and 60 percent and 52 companies with ratios between 40 percent and 50 percent at the end of 1970. (See table 20.6.) The companies outside these essentially traditional ranges generally have unusual characteristics of ownership, assets, competition, or business operations.

The capitalization ratios in table 20.7 are aggregates for all Class A and B investor-owned electric utilities. These indicate that common equity has remained within the narrow range of 35.4 to 39.0 percent of total capitalization for more than 30 years. The percentage for pre-

[3] Such sales increased to 16.3 percent in 1970.

ferred stock has moved gradually downward from about 15 percent at the beginning of the period to just under 10 percent at the end, while the percentage for long term debt crept up from about 48 percent to nearly 55 percent. As noted above, the companies also had a near record amount of short-term debt outstanding of $2.7 billion at the end of 1970.

Sources of Financing—Non-Federal Public Systems

The non-Federal publicly-owned electric systems rely on internal funds for capital expansion to a greater degree than the investor-owned systems. For systems reporting to the Federal Power Commission, external financing in the last few years has provided substantially more than has been provided either by additions to surplus or by depreciation and amortization charges. (See figure 20.3). Almost all external financing has been in the form of revenue bonds. Such bonds are exempt from the legal debt limits in effect in most municipalities. Because the interest on such bonds is exempt from Federal income taxes, these systems can borrow more cheaply than investor-owned companies. Capital contributions by governmental units provide only a minor portion of each year's financing requirements.

Sources of Financing—Federal Systems

Among the Federal systems, only the Tennessee Valley Authority is empowered to obtain funds in the private capital market by selling notes and bonds. TVA is authorized to borrow up to a total of $5 billion. Since 1959, when the borrowing authorization legislation was enacted, TVA has raised $828 million (net of repayments and refundings) by issuing its own securities. Such borrowing represented around 30 percent of TVA's total capitalization on June 30, 1969. The remaining capitalization primarily consists of appropriations from the U.S. Treasury. Debt service on notes and bonds, however, has precedence over repayment to the Treasury.

As in the case of investor-owned systems, TVA's interest costs on borrowed money have increased sharply in recent years. Partly as a result of this, TVA has raised its rates by fairly substantial percentages.

The other four major Federal systems, Bureau

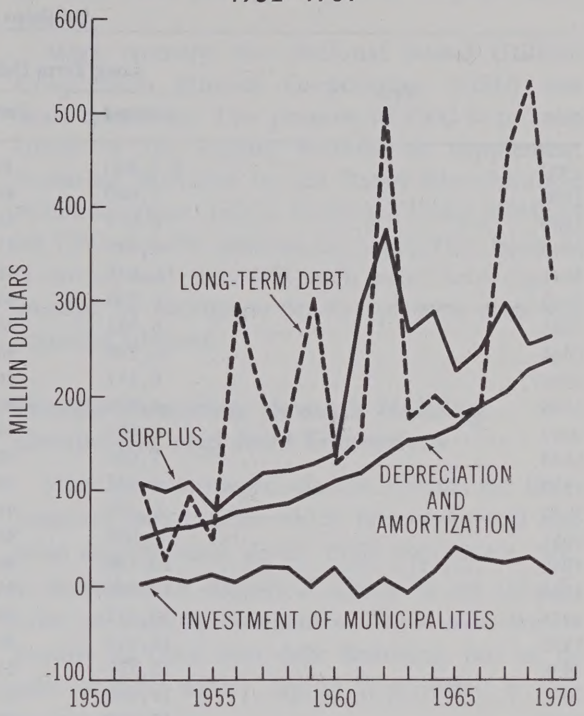
TABLE 20.6

Long Term Debt as a Proportion of Total Capitalization for 197 Investor-Owned Electric Utilities, December 31, 1970

Long Term Debt Percentage	Number of Companies
Less than 20.1	5
20.1–30.0	4
30.1–40.0	11
40.1–50.0	52
50.1–60.0	113
60.1–70.0	8
More than 70.0	4

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States, 1970.*

SOURCES OF FUNDS
NON-FEDERAL PUBLIC SYSTEMS*
1952–1969



Source: Federal Power Commission, Statistics of Publicly-Owned Electric Utilities in the United States.

*Excludes Power Authority of the State of New York. Approximately 70 percent coverage from 1952 to 1961 based on sales to ultimate consumers, and approximateley 80 percent from 1962 to date.

Figure 20.3

TABLE 20.7

Capitalization of Class A and B Investor-Owned Electric Utilities, 1937–1970

[Millions of Dollars]

Year	Long Term Debt		Preferred Stock		Common Equity	
	Amount	Percent	Amount	Percent	Amount	Percent
1937	$ 6,850	47.5	$ 2,125	14.8	$ 5,323	37.7
1938	7,060	48.5	2,092	14.4	5,296	37.1
1939	6,971	48.1	2,059	14.2	5,354	37.7
1940	6,895	47.3	2,078	14.2	5,508	38.5
1941	6,821	46.9	2,097	14.4	5,539	38.7
1942	6,753	46.9	2,135	14.8	5,430	38.3
1943	6,587	46.6	2,142	15.1	5,361	38.3
1944	6,370	46.1	2,146	15.5	5,269	38.4
1945	6,117	46.5	2,071	15.7	4,926	37.8
1946	6,129	46.1	2,029	15.2	5,106	38.7
1947	6,581	46.8	2,121	15.0	5,324	38.2
1948	7,693	49.1	2,178	13.9	5,765	37.0
1949	8,532	49.3	2,392	13.8	6,359	36.9
1950	9,178	48.9	2,574	13.7	6,980	37.4
1951	9,983	49.2	2,731	13.5	7,515	37.3
1952	10,796	48.7	2,896	13.0	8,432	38.3
1953	12,030	49.8	3,084	12.3	8,929	37.4
1954	13,312	50.4	3,280	12.4	9,659	37.2
1955	14,315	50.7	3,461	12.3	10,216	37.0
1956	15,210	51.1	3,686	12.4	10,853	36.5
1957	17,036	52.4	3,774	11.6	11,700	36.0
1958	18,558	52.8	4,023	11.4	12,575	35.8
1959	19,817	52.8	4,115	11.0	13,604	36.2
1960	21,034	52.8	4,280	10.7	14,524	36.5
1961	22,028	52.8	4,349	10.4	15,365	36.8
1962	22,912	52.4	4,497	10.3	16,296	37.3
1963	23,631	52.1	4,513	10.0	17,189	37.9
1964	24,588	51.8	4,557	9.6	18,352	38.6
1965	25,502	51.5	4,700	9.5	19,302	39.0
1966	27,728	52.3	5,040	9.5	20,283	38.2
1967	30,358	53.0	5,505	9.6	21,397	37.4
1968	33,519	53.8	5,982	9.6	22,766	36.6
1969	37,072	54.6	6,382	9.4	24,496	36.1
1970	41,938	54.8	7,499	9.8	27,045	35.4

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States.*

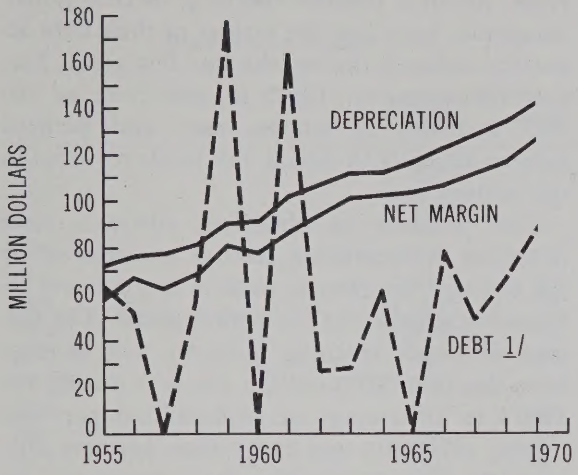
of Reclamation, Bonneville Power Administration, Southwestern Power Administration, and Southeastern Power Administration, are dependent entirely on Congressional appropriations for their financing.

Federal systems, as in the case of the other publicly owned systems, are not subject to Federal and state income taxes or to local property taxes. TVA, however, as well as a number of other nonprivate systems, makes some payments in lieu of taxes to state and local governmental units.

Sources of Financing for Cooperative Systems

Since the creation of the Rural Electrification Administration in 1936, more than $7 billion in loans to cooperative systems have been approved by REA of which more than $2 billion of principal has been repaid. Under the Pace Act of 1944, the interest charge on REA loans was set at 2 percent with a repayment period of 35 years. As of December 31, 1970, the net investment in cooperative electric systems was about $5.2 billion.

SOURCES OF FUNDS
DISTRIBUTION COOPERATIVES
1955–1969



Source: Rural Electrification Administration (REA Bulletin 1-1), Annual Statististical Reports.

1/ Annual increase in long term debt outstanding.

Figure 20.4

The principal source of funds for distribution cooperatives during the last 10 years has been depreciation accruals and net margins, with less than 25 percent coming from borrowed capital usually in the form of REA loans. (See figure 20.4.) For generating and transmission (G&T) cooperatives, which have been growing more rapidly than the others, borrowed funds are still the main source of new capital. (See figure 20.5.)

At present, cooperative systems (especially G&T cooperatives) are handicapped in seeking funds in the private capital market because of their high debt ratios and low interest coverages. Moreover, any outside borrowing would be subordinated to their REA mortgages which, by law, represent a first lien on the cooperatives' assets.[4]

The possibility of joint undertakings by private and cooperative systems is illustrated by the Buckeye project in Ohio. A group of 27 cooperatives joined with the Ohio Power Company, an investor-owned system, in financing two 615 megawatt generating units which were completed in 1967. The Buckeye cooperatives raised $62 million in the open market to finance their share of the facilities, i.e., ownership of one of the two units plus participation in joint facilities.

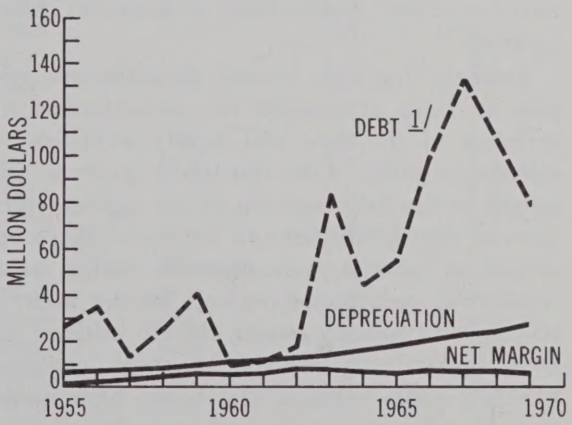
More recently, the National Rural Utilities Cooperative Finance Corporation (CFC) has been organized. The purpose of CFC is to raise funds in the capital markets to supplement financing provided by the Rural Electrification Administration. Initial funds are being provided by CFC member systems on a pro rata basis. It is anticipated that CFC will raise debt capital secured by mortgages on the projects receiving financial support.

Private Financing through Holding Companies and Joint Enterprises

Most investor-owned electric systems are independent corporations which borrow capital and raise equity funds under their own name, but, as described in chapter 2, about 80 are subsidiaries of holding companies. These subsidiaries usually do their own debt financing, but all or part of their equity capital is provided by the parent company.

Another form of joint enterprise is exemplified by the "Yankee" companies in New England. The Yankee Atomic Electric Company, or-

SOURCES OF FUNDS
G & T COOPERATIVES
1955–1969



Source: Rural Electrification Administration (REA Bulletin 1-1), Annual Statistical Reports.

1/ Annual increase in long term debt outstanding.

Figure 20.5

[4] Financing through the National Rural Utilities Cooperative Finance Corporation is an exception.

ganized in 1954 by 12 sponsoring investor-owned utility companies, was formed to provide a broader economic base for sharing the large financial burden and risk associated with a nuclear generating station. Thirty-five percent of the total cost of the Yankee Atomic plant was financed by sales of common stock to the sponsoring companies. Entitlement to the capacity and energy from the plant is in proportion to their respective equity investments. The remaining cost of the plant was financed through a combination of bonds and bank loans by Yankee Atomic. Three more "Yankee" companies have since been formed with essentially similar organizational structures.

Other utilities, including some of the nation's largest systems, have also engaged in various types of joint financing arrangements to capture the scale economies inherent in giant-sized generating units. This pattern of institutional innovation appears to be spreading, as more companies find that they are not in an advantageous position to go it alone with the required capital investment for the most technologically advanced large units.

Outlook for Future Financing

Electric utilities have had important advantages over many other industries in competing for funds in the private capital markets. The comparative stability of their earnings, the persistent growth of electricity demand, and the gains in productivity from advancing technology have, together, commanded a premium from investors.

Recently, however, several developments appear to have diminished the attractiveness to investors of the debt and equity securities of electric utilities. The continued gradual increases in the debt portions of the capital structures of electric utilities and the recent sharp increases in interest rates discussed earlier have resulted in substantial declines in the interest coverages of investor-owned electric utilities. In 1964, the industry average before-tax earnings was 5.07 times interest, and many high grade electric utility companies had coverages of 6 or 7 times interest. By 1969, the average before-tax earnings for the industry had dropped to approximately 3.7 times interest, and by 1970 had fallen further to 3.1 times. The combined result of rising debt ratios, high interest costs and reduced coverages has been reductions in the credit ratings of many electric utility debt securities. About a third of the large electric power companies have had the ratings of their debt securities reduced during the last few years. Further reductions are likely to contribute to further increases in interest costs and perhaps greater difficulty in raising the funds required in the coming years.

The problem of obtaining adequate debt financing at reasonable costs is exacerbated by the fact that the electric utilities face a heavy refinancing schedule in the period ahead. The volume of bonds reaching maturity will increase from less than $100 million per year during the 1960's to an average of $550 million per year during 1971–1974 and $1.2 billion per year during 1975–1979. Thereafter, the amounts will be somewhat larger. (See table 20.8.) Since most of the maturing bonds carry coupon rates below 5 percent, the necessary refunding will increase materially the embedded debt costs of the utilities unless market rates decline substantially from current levels.

It is also apparent that investor interest in electric utility common stocks has diminished in recent years. During the period 1956 through 1965 the Standard and Poor's index of electric utility stocks increased about 125 percent as compared with an increase in the index of industrial stocks of about 85 percent. Since that time, while industrials have risen by about an additional 10 percent, the index of electric utility stocks has fallen by more than 30 percent. A number of developments have contributed to this apparent disenchantment on the part of investors with electric utility common stocks. Undoubtedly, the problems that the industry has been experiencing with respect to reliability and adequacy of power supply and with respect to problems of environmental impact have caused a certain amount of investor uncertainty concerning the future of the industry. In addition, although the long term trend in rate of return on book value of electric utility common stock equity securities has been upward, it has been declining somewhat since 1967 as shown in table 20.9. This is particularly significant in view of the fact that the proportion of equity in the capital structures of electric utilities has continued to decline as shown in table 20.7. Both

TABLE 20.8

Schedule of Electric Utility Debt Falling Due 1971–2005

[Bonds issued through 1970]

Year	Amount (Millions)	No. of Issues
1971	453	32
1972	351	24
1973	428	31
1974	977	51
1975	1,886	83
1976	1,079	53
1977	1,054	78
1978	767	94
1979	1,016	92
1980	981	79
1981	809	62
1982	1,691	91
1983	825	69
1984	1,337	99
1985	994	61
1986	1,046	61
1987	1,392	82
1988	1,495	86
1989	944	56
1990	1,326	69
1991	1,132	63
1992	1,411	67
1993	1,566	70
1994	1,364	51
1995	1,417	58
1996	1,955	72
1997	2,296	85
1998	2,486	86
1999	2,776	94
2000	3,448	99
2001	195	3
2002	100	1
2003	40	1
2004	45	1
2005	180	3

Source: FPC Form 1.

of these developments in combination with rising interest rates have resulted in the sharp decline in interest coverages described above which increases the risk of common stock equity.

Another important change that has occurred since the mid-1960's has been the growth in the proportion of the net earnings of electric companies arising from bookkeeping credits for interest capitalized on construction work in progress. As electric companies' construction activities grow as a proportion of their total business, this interest credit has become a correspondingly growing proportion of earnings. Thus, any significant decline in construction programs may have a significant adverse impact upon electric utility earnings.

Finally, the attractiveness of the industry's securities is also dependent upon the posture of public utility regulation especially as it affects electric utility revenues. In the recent period of very high interest rates and sharply rising costs, investors have been understandably concerned lest the regulatory system be laggard in sanctioning rate increases to cover the higher levels of costs. Regulatory responses which diminish such uncertainty will tend to reduce the cost of capital to utilities, for it is a paradox of regula-

TABLE 20.9

Earned Rates of Return and Average Interest Rates, Investor-Owned Electric Utilities, 1946–1970[1]

	Percentage Rate of Return on Common Stock Equity	Percentage Rate of Return on Net Utility Investment	Average Interest Rate on Long Term Debt
1947	10.3	6.5	3.0
1948	9.9	6.0	3.0
1949	10.6	6.2	3.0
1950	10.6	6.0	2.9
1951	9.6	5.6	2.9
1952	10.3	5.8	3.0
1953	10.3	5.7	3.1
1954	10.6	5.7	3.2
1955	11.0	5.9	3.1
1956	11.1	5.9	3.1
1957	11.0	5.7	3.3
1958	11.0	5.7	3.4
1959	11.2	5.8	3.5
1960	11.3	5.9	3.6
1961	11.2	6.0	3.6
1962	11.7	6.3	3.7
1963	11.8	6.4	3.7
1964	12.3	6.4	3.7
1965	12.6	6.6	3.8
1966	12.8	6.6	3.9
1967	12.8	6.6	4.0
1968	12.3	6.4	4.3
1969	12.2	6.4	4.6
1970	11.8	6.2	5.1

[1] About 10 percent of total utility investment is for utility plant other than electric plant.

Source: Federal Power Commission, *Statistics of Privately-Owned Electric Utilities in the United States.*

tion that significant delays in permitting higher costs to be reflected in higher rates may ultimately result in higher costs of capital and higher rates. It is therefore important that state and local regulators as well as this Commission exercise diligence in minimizing regulatory lag.

The industry's financial requirements for the next two decades are exceedingly large. This Survey does not attempt to delineate or predict the specific methods by which the facilities may be financed to supply the immense increases in load projected in earlier chapters. It is obvious, however, that the ability of the industry to fulfill these requirements for load growth will depend on its continued success in raising large and growing amounts in the capital market.

CHAPTER 21

RESEARCH AND DEVELOPMENT NEEDS OF THE INDUSTRY

Introduction

The 1964 National Power Survey emphasized the need for expanded and coordinated research activities in the electric power field. Soon after the survey was published, a report of the Select Ad Hoc Research Committee [1] was issued in which the need for more research and development (R & D) effort and for greater support of such work by the electric power industry was clearly recognized. That report recommended formation of a joint research council consisting of representatives from investor-owned utilities, Federal power agencies, state and local government power agencies, and cooperatives. The stated objectives were to bring together representatives of the various industry segments to appraise research affecting the industry, identify areas of needed research, participate in such research, and exchange reports on research.

The Electric Research Council (ERC), an organization such as that recommended by the Select Ad Hoc Committee, was formed early in 1965. Membership includes representatives of the four utility ownership categories as suggested by the Committee. The Council serves as a medium for joint sponsorship of research projects by those members who have mutual interest and concern in the various areas of research activity. Many of the major projects have received primary financial support from the Edison Electric Institute. In addition, individual utilities, other utility organizations and the Federal government have sponsored or participated in specific projects related to their particular interests.

For the past several years, the largest single area of R & D expenditures has been the nuclear field, involving reactors, fuel, and related nuclear power plant facilities. Other major areas of investigation have been transmission systems, with particular emphasis on underground and ultra-high-voltage (UHV) overhead transmission, environmental problems, particularly air pollution and the environmental effects of cooling water discharges from thermal power plants; improvement in power plant equipment, new forms of generation, advanced control systems, better techniques in lightning surge control; and related problems in the design and operation of power systems.

One slightly different research activity involves an extensive effort sponsored by the utility industry to develop an improved storage battery for electric vehicle motive power. This work can, of course, make an important contribution to solving the problem of urban air pollution, nearly half of which is said to result from automotive discharges.

In the United States much of the R & D work has been performed by the electrical equipment manufacturers. In 1969, they and other electric power industry suppliers reported some $110 million of R & D expenditures.

During the same year, electric utilities reported research and development expenditures of about $40 million, or less than one-fourth of one percent of gross electric operating revenues, but this figure does not include significant costs of delays and start-up expenses incurred because of R & D type work carried on at the site of new equipment. The continued growth in use of electric energy, public demand for environmental protection, competition for land and water use, and concerns about overall energy resources all indicate the need for a considerably higher level of regularly budgeted research and development activity. The Commission therefore has

[1] An eleven-member committee formed by the Federal Power Commission in July 1963 to study and make recommendations concerning a permanent industry-wide organization to encourage and coordinate research and development activities in the electric power industry.

recently revised its rules concerning the accounting treatment for R & D expenses to encourage more active participation by the utilities in investigation which provide promise for meeting power supply problems of the future.

On June 4, 1971, President Nixon sent to the Congress a message on energy in which he outlined a program to facilitate research and development for clean energy. This program included a commitment to complete the successful demonstration of the liquid metal fast breeder reactor by 1980; more than twice as much Federal support for sulfur oxide control demonstration projects in fiscal year 1972; an expanded program to convert coal into a clean gaseous fuel; and support for a variety of other energy research projects in fields such as fusion power, magnetohydrodynamic power cycles, and underground electric transmission.

The Commission endorses these programs and urges that the level of R & D activity in these and other areas be increased so that the electric utility industry, in conjunction with Government, equipment manufacturers, and the coal, petroleum, and other resource industries, can develop as soon as possible, new methods, equipment, fuels, and systems planning required to meet increased demands for electricity with minimum impact on the environment.

Distribution

The Distribution Technical Advisory Committee in its June 1969 report to the Federal Power Commission, identified automatic or remote-controlled switching devices for distribution feeders as a most challenging need. These devices would provide immediate identification and isolation of a faulted line section and would restore service to the remainder of the circuit. It indicated that considerable development work will be required before the necessary switchgear, communication channels, and controls become economically feasible for general application on underground and overhead circuits.

Experimental installations are being made on some distribution systems to monitor, remotely, individual equipment components and customer services and to provide immediate notice of abnormal conditions or failure. Future goals include the development of practical means for remote monitoring of each customer's service and each line transformer, remote reading of each customer's meter, and remote operation of distribution line switches over a common communication channel.

Other needs include smaller pad-mounted transformers, smaller switching cubicles, and simplified connectors.

The extensive shift to underground distribution in the recent past has left scant time for equipment development. Many new concepts are being applied in an effort to reduce the cost of underground facilities and extend their application. While most of the new concepts and designs should operate satisfactorily, comparative designs and thorough testing were not always possible, so research directed toward design improvements should be fruitful.

Lightning has been and will continue to be a primary cause of overhead distribution line outages in many parts of the country. The general trend is toward the use of higher insulation levels for distribution circuits and lightning arresters or overhead ground wires for lightning protection. Performance has improved accordingly, but more knowledge of lightning stroke frequency and characteristics in particular service areas would be helpful.

Mathematical models are being developed to evaluate the overall reliability of various distribution systems. Continued model development is recommended to provide more precise methods for improving reliability.

Transmission

Extensive research programs are under way to develop new methods and materials for the electric power transmission systems of tomorrow. The studies are supported by both utilities and electrical equipment manufacturers. Foreign equipment suppliers are participating in a few of the development programs concerned with new, higher voltage equipment for use in future UHV systems.

Underground Cables

The extremely difficult problems of obtaining transmission line rights-of-way in urban areas and the growing problems in both suburban and rural areas, coupled with more recent concerns about the environmental and esthetic ef-

fects of overhead lines, have resulted in extensive research and development related to underground facilities. Among the major problems of long high-voltage ac cables are the high charging currents. The large compensation necessary creates serious problems in the design and operation of an underground ac system, and adds materially to the cost. Several manufacturers and utilities are working on various methods of increasing pipe-type cable ratings by forced circulation of cooling oil. This approach appears to offer promise of increased capability and lower transmission costs for both existing and future cable installations.

The Electric Research Council is sponsoring a $17 million underground transmission R & D project involving the study of several different techniques and the development of related equipment for high capacity, long-distance underground transmission. One part of the program involves testing and evaluating cable samples by means of aging and overvoltage tests. Both steady state and cyclic operation of cable test loops are used to produce temperatures and voltages equivalent to those expected under maximum operating conditions. The Waltz Mill cable test station, figure 21.1 near Pittsburgh, Pennsylvania, is capable of testing and evaluating cable systems from 138 to 1,100 kilovolts, although there are no plans to utilize voltages above 750 kilovolts before 1990. The extra-high-voltage (EHV) section has been in use since August 1969 for testing 500-kilovolts pipe-type cable, and it appears that such cable should be available for commercial use in the mid-1970's. The HV section was employed more recently to evaluate new cable designs in the 138 and 230 kilovolts classes.

The ERC underground transmission program has several short-range objectives, including extension of the voltage range of oil-impregnated, paper-insulated cable and other existing types of insulated cable, improvement of power transfer capability of present systems, development of faster and less expensive cable splicing methods and procedures, development of extruded insulation for high-voltage cables, and development of synthetic tape insulation for EHV cables.

Other goals of the underground transmission R & D program include the development of compressed gas insulation systems; development of cryogenic and superconducting cables; reduction in cable installation costs; improved joint use of rights-of-way; and development of advanced concepts such as underground microwave transmission.

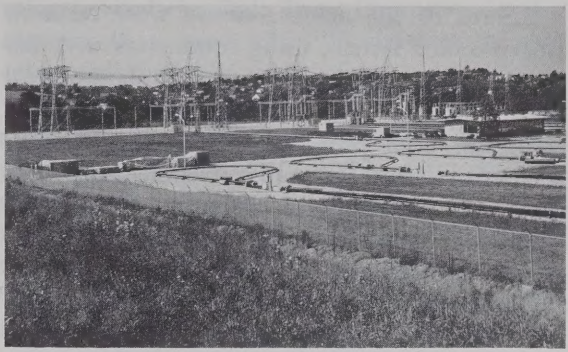


Figure 21.1—Waltz Mill cable test station near Pittsburgh, Pennsylvania.

Several separate projects involving compressed gas insulation (CGI) systems are now being carried out. The CGI systems are particularly attractive because of their lower charging currents and dielectric losses and because of their heat removal capabilities. It has been suggested that CGI cable might have as much as three to four times the capacity of conventional pipe-type cable. If this is true, much longer cable lengths would be feasible for ac applications. Power handling capability of about 2,000 megavolt amperes per 345 kilovolts circuit appears at this time, to be a reasonable goal for near-term development. This compares to a maximum capability of 500 megavolt amperes or less for the highest-voltage (345 kV) underground cables in service today. Two manufacturers have developed sulfur hexaflouride (SF_6) gas-insulated, spacer-type designs for use at 345 kilovolts and are expected to have 500 kilovolt designs ready for performance tests in the early 1970's.

With respect to cryogenic cable systems, a recent technical paper [2] reports that capital costs might run about $1,200 per megawatt-mile for a double-circuit conventional pipe-type cable of about 1,300 megawatts capacity; $800 per megawatt-mile for a single-circuit cryogenic cable system of about 3,500 megawatts capacity; and $600 per megawatt-mile for a similar circuit of 5,000 megawatts capacity.

[2] "Cryogenic Cable Systems for High Capacity Underground Transmission Systems," American Society of Mechanical Engineers, Paper 69–WA/PID 14, 1969.

Results of one manufacturer's work on a nitrogen-cooled system, using conductors with dielectric spacers in a high-vacuum insulation, have been sufficiently encouraging that a 345-kilovolt cable has been proposed which is said to be competitive with oil-paper insulated pipe-type cables for capacities of about 1,000 megavolt amperes or more in the 138-, 230-, and 345-kilovolt voltage classes.

One contractor is currently engaged in a million dollar, three-year study of resistive cryogenic systems for the ERC. If R & D progress continues as projected, the resistive cryogenic system may be available for utility application for circuits of about 4,000 megavolt amperes capacity by about the end of the 1970's. Both liquid hydrogen and nitrogen have been used as coolants, but liquid nitrogen appears to be the better choice for the near future.

Investigations up to this time indicate that superconducting cryogenic systems, as distinguished from resistive systems, have little to offer in the 3,000 to 5,000 megavolt amperes capacity range, but may be attractive in the 7,000 to 10,000 megavolt amperes range. While there does not appear to be a near-term requirement for circuits in this higher capacity range, R & D on superconducting systems is quite properly being carried out with a view to longer-term needs.

One project in the ERC research program has involved the development of a niobium-plated copper pipe suitable for use as a superconductor in an ac application. The initial research results offered sufficient promise that the contractor proposed an $8 million program of further development to refine earlier work. This concept appears capable of providing a means for transmitting as much as 10,000 megavolt amperes per circuit at 345 kilovolts if technical problems, such as proving the suitability of liquid helium as a cable insulating medium at higher transmission voltages, can be solved. Further developmental work might make utility application possible sometime in the 1980's.

The fact that known superconducting materials require liquid helium temperatures (below —450°F.) to maintain a superconducting state has led to efforts to develop materials with superconducting states at higher temperature. This would afford a large reduction in cost through reduced refrigeration requirements.

Aside from the problems associated with superconducting cables themselves, cables of such high capacity will introduce other important system problems, such as development of high-capacity terminal equipment and provisions for reserve capacity in the event that a cable is out of service.

As discussed later in more detail, several manufacturers and utilities are involved in high-voltage dc research. It has been suggested that HVdc and cryogenic cable systems may represent an ideal combination for underground installations in congested metropolitan areas and other locations where underground installation is required.

Efforts have been made to develop extruded dielectric insulation, but elimination of voids in the insulating material has proved difficult. Because of this problem, another part of the ERC program is aimed at developing a polymeric paper with good dielectric properties. Such a synthetic paper could be applied with the same machines that have been used in the manufacture of cellulose paper-insulated cables. One experimental program has involved synthetic papers impregnated with cryogenic fluids to produce a flexible cable assembly for installation in a pipe filled with liquid nitrogen.

The overall results of research efforts seem to offer promising opportunities for reducing the cost of underground transmission. Before some of the types of cable mentioned will become available for general use by the industry, much development work will be required to assure reliable, safe, and economical installation and op-

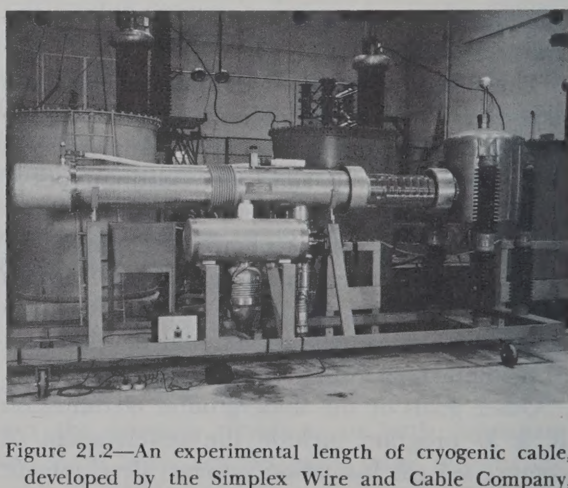


Figure 21.2—An experimental length of cryogenic cable, developed by the Simplex Wire and Cable Company, undergoing high-voltage tests.

eration. Refrigeration and pumping equipment for cryogenic installations may require special R & D efforts. Installation and operating procedures for future high capacity underground cable systems must also be developed along with the equipment and facilities.

In view of the large electric power loads forecast for the future, the rapidly growing need for underground facilities in many areas, and the need for lower costs, the R & D effort presently devoted to underground transmission may be too small. Past R & D work has been supported largely by electric utilities and cable and equipment manufacturers. However, manufacturers do not have as much economic incentive to assist in this program as for many other research programs because the likelihood of achieving a breakthrough is more remote, thus reducing the prospect of early returns on investments. An adequate research program would require greater cooperation and financial participation by utilities, manufacturers, and Government. Without new developments, the choices for future transmission line locations, and thus for generating plant sites will surely be limited.

Ultra-High-Voltage Alternating Current Systems

Research and development work is now being carried out both in the United States and in some foreign countries on ultra-high-voltage (UHV) levels which some predict will be needed for overhead transmission systems within as few as 10 years. Although no specific nominal value for the next step above 765 kilovolts has been selected, and some experts have warned against premature selection of such a level, the studies now under way revolve primarily around two nominal values—1,000 kilovolts and 1,500 kilovolts. The Electric Research Council's 1970 program for UHV research totalled about $4.5 million, not counting the financial support of the manufacturers involved. Much of the experimental work is being done at the General Electric Company's UHV Facility near Pittsfield, Massachusetts. Studies cover equipment hardware designs, conductor handling and configuration, insulation and switching surge problems, and phenomena relating to arc behavior at the higher voltage levels.

The American Electric Power Company, ASEA (Allmanna Svenska Elektriska Aktievolaget), and the Ohio Brass Company are also engaged in a joint effort to develop suitable equipment for UHV application.

Up to about the 765 kilovolt levels, insulation arrangements required to withstand lightning potentials, together with suitable shunt reactors, are generally adequate for switching surge and insulator contamination problems. These latter may become primary concerns, however, at the higher operating voltages anticipated for the future.

To reach the 1,000 to 1,500-kilovolts nominal levels, satisfactory ways must be found to limit surge potentials to, perhaps, 1.5 times the nominal operating voltage. Various arrangements of circuit switching equipment and other means of limiting surge crests are being studied.

Salt, industrial by-products, and other atmospheric contaminants can greatly reduce the insulating strength of exposed equipment. The addition of insulator elements and use of special designs with increased creep distances may not

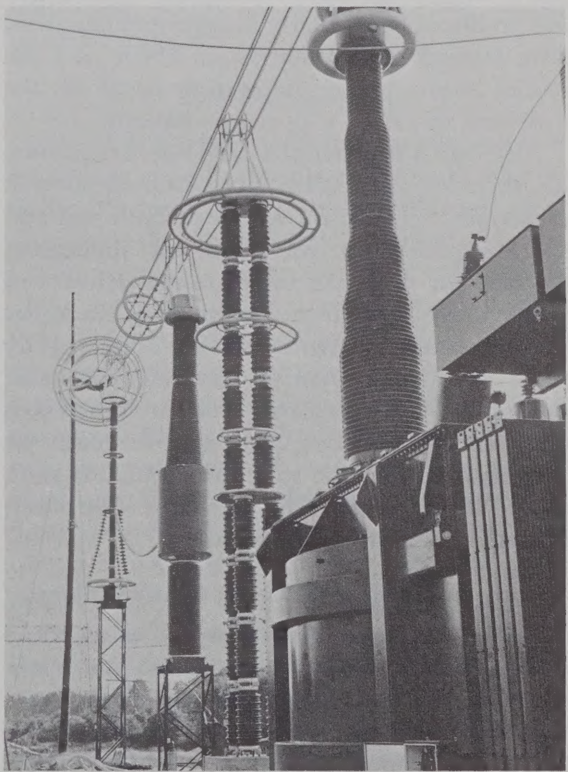


Figure 21.3—Experimental ultra-high voltage bus equipment, located at General Electric Company's Project UHV Facility is used for studies of ac transmission problems.

offer a complete solution of the problem for future UHV equipment. Contamination is seen as one of the dominant factors which may determine design as voltage levels increase into the UHV range.

More work is needed to establish the practical limits imposed by air as an insulating medium and by other factors affecting maximum feasible transmission voltage levels for the future.

Also, investigations are in progress to determine the adverse effects on substation equipment of spurious currents such as those resulting from solar magnetic disturbances. While these currents have not caused serious difficulties with present HV and EHV equipment, the problem is expected to be more severe at higher voltage levels.

High-Voltage Direct Current Transmission

Research and development of high-voltage direct current (HVdc) for power transmission and for other special purposes has had the support of some manufacturers and utilities, particularly during the last several years. Recent siting problems, particularly in metropolitan areas, have focused more attention on HVdc as a potential means of circumventing some of the problems associated with ac installations.

Although a number of HVdc lines are in service, there are great needs for additional research on terminal equipment to reduce both cost and space requirements. An important application foreseen for dc is the underground delivery of power to the downtown areas of large cities, but the dc terminal designs now available require more land area than is generally available downtown. Other research work in progress is designed to determine the corrosive effects on underground metallic structures, and this work should be expanded to include large scale effects in congested metropolitan areas.

Environmental and Esthetic Considerations

One of the environmental aspects of overhead transmission is the problem of radio and television interference at the higher transmission voltages. Audible noise could also present a difficult problem for the higher voltage lines of the future.

Conductor bundling with more conductors per bundle than presently used may be required for UHV lines to reduce corona discharges and resulting electrical losses and interference problems. Practical and economic corona-free equipment for the future offers a substantial design challenge.

Problems of induced voltages and buildup of electrostatic charges on metallic objects in the vicinity of power lines become more pronounced at UHV levels, and could present stubborn problems with future installations. A CIGRE (International Conference on Large Electric Systems) group is compiling data on limiting conditions involved with UHV transmission lines.

Undergrounding of power facilities is often considered to be the solution to environmental problems associated with surface and overhead installations. Although underground installations may provide acceptable answers to some appearance problems, they may create new problems such as those stemming from soil instability, erosion, and heat dissipation, and the disturbance of road and other rights-of-way which necessarily accompanies any cross-country underground construction.

Considerable effort has been devoted to the design of more artistic and graceful structures for both substations and transmission lines, and color treatment and area landscaping have been used effectively in making power facilities less obtrusive. Further efforts in these directions are

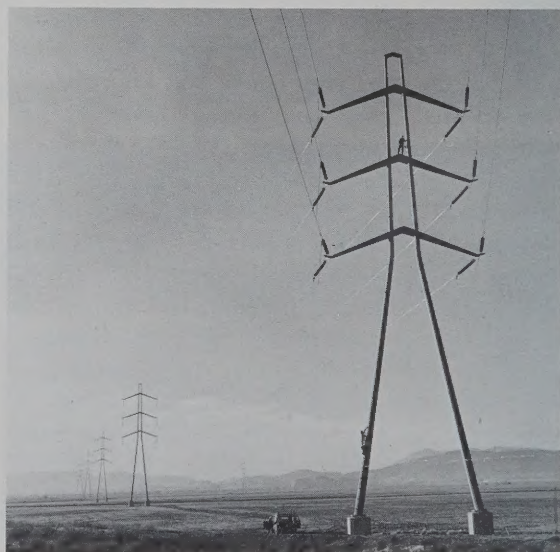


Figure 21.4—New design of a 230-kV transmission tower by Pacific Gas and Electric Company.

expected. In addition, the development of new insulation systems might simplify some problems of esthetic acceptability for future transmission facilities.

Conductor vibration and spacer requirements for the multiple conductor bundles necessary for UHV lines are other appropriate areas for extensive research and study. Problems associated with higher cable tensions could influence both tower designs and right-of-way widths.

Generation

Research expenditures for nuclear reactors and associated power plant equipment have in recent years overshadowed expenditures for any other phase of R & D activity related to generating facilities. Although the investor-owned utilities, TVA, and several REA cooperatives had committed through the end of 1970 nearly $15 billion to nuclear power plant construction, a very large part of the total R & D effort, including experimental projects, was financed with Federal funds.

Apart from nuclear R & D, there are many opportunities for further improvement in generating plants, including improvement of steam facilities (fossil as well as nuclear), better plant siting practices, the development of materials to better withstand higher temperatures and pressures, improved flame detection for coal-fired units, improved water treatment, better controls and control techniques, new hydroelectric designs, possible new methods of generation, improved fuels, and ways of solving ecological and other environmental problems. These and other areas for R & D are discussed later in this chapter.

Plant Siting

Today's difficulties in finding suitable and acceptable sites for generating plants emphasize the importance of new plant siting concepts and siting arrangements, which may vary significantly from common practices of the past. Research to identify the best locations for generating plants should be expanded and intensified. Factors to be considered include the appearance, location, and visual appeal of structures, as well as air pollution, thermal effects, noise, and land use for fuel storage and ash disposal. High priority should be given to a systematic analysis of such factors, along with engineering requirements. Some of the possibilities for constructive research are:

1. Undergrounding of nuclear plants.
2. Use of offshore man-made islands or floating platforms for large steam-electric plants to solve some of the troublesome problems of land availability, esthetics, air pollution, and cooling water availability.
3. Underground reservoirs, in combination with lakes or oceans as upper reservoirs, for pumped storage projects.
4. New studies involving geology, seismology, rock mechanics, and soil dynamics to provide better basic data for new siting concepts.

The National Academy of Engineering, through its Committee on Power Plant Siting, has undertaken a program to develop a basis for optimizing power plant siting. The electric utility industry has joined with the National Science Foundation, the Atomic Energy Commission, and others in providing the needed financial support.

Nuclear Facilities

The R & D effort to bring nuclear power to its present state has involved comprehensive activity and investigation in the following areas: physics; fuels and materials; fuel cycles, including processing, fabrication, and reprocessing; plant and core design; reactor system components; reactor system coolants; nuclear plant instrumentation and control; safety; highly radioactive waste disposal; and other areas of technology, including material development, which help assure safe, reliable, and economical nuclear plant operation. Utilities are also engaged in further development of analytical methods and computer programs for coordinating the several phases of nuclear power management.

Past efforts have been directed primarily to the development of light water and gas-cooled reactors. It appears that the needed future research and development in this area will be carried on primarily by industry—manufacturers and utilities—rather than by the Atomic Energy Commission. The AEC will, however, continue work with respect to plant safety and improvements in fuel resource utilization.

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The AEC, today, is focusing its attention on the breeder, and is asking the manufacturers and utilities to invest heavily in breeder reactor development. Fundamental to the planning and execution of its reactor development programs has been recognition of needs and responsibilities concerning the utilization of natural resources, the health and safety of the public, and the protection of the environment. A vigorous breeder reactor program is believed to be an essential element in meeting these responsibilities.

There has been interest also in advanced converter and low gain breeder concepts because of their promise for greater economy and higher conversion ratios than obtained with current pressurized or boiling water reactor designs. The Federal effort has been narrowed to three approaches—the seed and blanket light water breeder concept, the molten salt breeder concept, and the high-temperature gas-cooled concept.

The thorium-uranium 233 seed and blanket light water concept (LWBR) has an expected conversion or breeding ratio high enough to increase fuel utilization significantly beyond that of present reactors. The design is based on proven pressurized light water technology and, therefore, except for changes in the reactor core, may not require significant advances beyond present technology.

The high-temperature gas-cooled reactor (HTGR) is a helium-cooled, graphite-moderated concept with a potential for lower costs and higher conversion ratios than present light-water designs. A 40 megawatt prototype gas-cooled reactor at the Peach Bottom Plant in southeastern Pennsylvania began operating in 1967 and served as a forerunner to the 330 megawatt HTGR being built near Platteville, Colorado, for operation in 1972.

Present indications are that the HTGR will have higher thermal efficiencies, probably in the order of 40 percent, compared to about 33 percent for light water reactors. Also, the HTGR is somewhat more efficient in its fuel utilization than present reactor systems, since it recovers about two percent of the energy contained in the naturally occurring reserves of uranium. If there are substantial delays in development of the breeder reactor, the HTGR has the potential for reducing the effect of the delay on uranium utilization.

The Breeder

The fast breeder reactor offers the prospect of increasing the utilization of the energy contained in naturally occurring uranium, from the 1 to 2 percent recovered by conventional light water reactors to something over 50 percent. The world energy needs for centuries to come will be assured if the fast breeder reactor is developed and widely applied. Use of the breeder reactor for electric power production will also save equivalent supplies of fossil fuel resources which are limited and needed for other uses.

The importance of the breeder's fuel conservation is emphasized by the expectation that nuclear-generated power is expected to grow from less than two percent of electric utility generation in 1970 to an estimated 28 percent by 1980, and 49 percent by 1990. Another advantage of the breeder is its improved efficiency over conventional nuclears leading to a reduction of about one-third in a plants waste heat discharges to the environment.

While both gas-cooled and liquid-metal-cooled fast breeders are being researched, the liquid metal fast breeder (LMFBR) appears to be the best candidate for commercial feasibility during the next several decades. The technical feasibility of the LMFBR has been demonstrated by successful operation of a number of experimental reactors in the United States and abroad. The AEC has supported an intensive LMFBR research and development program since about 1966 and in FY 1970 AEC spent an estimated $122 million on this effort. In addition, the utilities have contributed to fast breeder research, principally through their support of the Fermi plant and the SEFOR [3] fast reactor at Fayetteville, Arkansas. Utilities also are contributing to the fast breeder demonstration plant design studies of General Electric, Westinghouse, and Atomics International. Large research and development programs on the LMFBR are also under way in Europe, Japan, and the USSR.

The next step in the development of the

[3] Southwest Experimental Fast Oxide Reactor is being used to obtain physics and engineering data at various fuel compositions, temperatures, and crystalline states characteristic of power reactor operating conditions. The project is sponsored by 17 investor-owned electric power companies, General Electric Company, the Atomic Energy Commission, and the Karlsruhe Nuclear Research Center of West Germany.

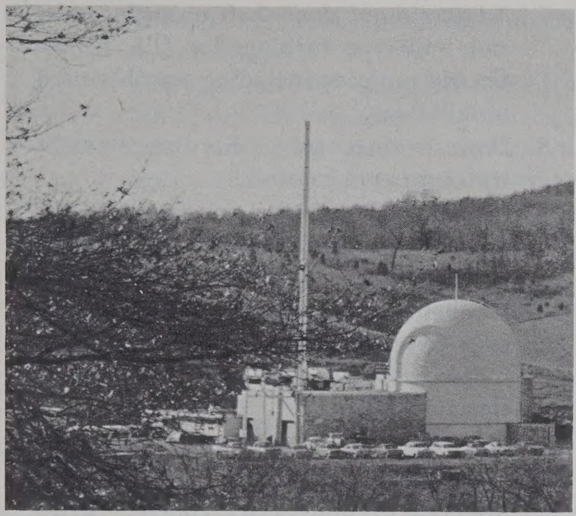

Figure 21.5—The Southwest Experimental Fast Oxide Reactor (SEFOR) near Fayetteville, Arkansas.

LMFBR is the construction of at least one, and preferably two, demonstration plants in the 300 to 500 megawatt capacity range, which are needed to expand the base of technical knowledge, narrow technical and economic uncertainties, develop managerial and operational experience, and provide for a viable and competitive LMFBR supply industry. Demonstration plants should show that fast breeders are safe, reliable, environmentally compatible, and have economic potential to produce electricity at a cost competitive with other forms of generation.

To this end, AEC is proceeding with an LMFBR Demonstration Program, which has as its objective the construction by the utilities for at least one such demonstration plant, with the government and the utilities sharing in the costs. The program envisions that such a plant or plants would be operated by electric utilities as part of their systems. If successful, these plants should lead to large commercially feasible LMFBR's by the late 1980's. This program is estimated to cost about $2 billion.

A group of 41 utilities from the United States are participating with Gulf General Atomic and others in a modestly funded research program aimed at continuing the development of the gas-cooled fast reactor (GCFR). Interest is also continuing in the development of the Molten Salt Breeder Reactor (MSBR), a concept being developed at Oak Ridge National Laboratory. This concept would use thorium as a fuel.

It is believed that high priority should be given to construction of at least one LMFBR demonstration plant. There appears to be adequate technological development to assure success. Each demonstration plant is estimated to cost from $300–$600 million. Government and industry undoubtedly will need to share in the funding and economic risk.

There are also government and industry views that the GCFR offers promise of success sufficient to justify more vigorous R & D effort directed to its earlier availability for power plant use.

Fossil-Fueled Generation

The most important research and development needs related to fossil-fueled generation are in the areas of air pollution and thermal effects upon water used for cooling purposes.

A continuing need of coal-fired units is more reliable flame detection. Equipment for this purpose is relatively dependable and economical for gas and oil-fired steam generators, but in coal-fired applications detection problems are created by such things as difficulties in igniting coal, variations in the point of coal ignition, changes in coal characteristics, masking caused by coal particles, difficulties in detecting the flames of individual burners, slagging, and dirt deposits.

The Generation Technical Advisory Committee suggested a number of problem areas related to steam generation generally which may merit concerted effort toward new solutions and improved methods. Among the needs are:

1. Development of better materials with particular emphasis on metals and the improvement of boiler tube materials for higher throttle temperatures.
2. Solutions to problems in water treatment and oxygen contamination of internal pre-boiler and steam generator unit components.
3. Provision for greater operating flexibility in large units. This problem becomes more pronounced as the large units, many of which will be nuclear, move up on the load curve from base load to the intermediate range where cyclic operation will be required.
4. Means of decreasing the damage to pressure reducing valves in start-up systems.

The relatively short life of once-through boiler start-up valve equipment as currently designed could present real problems in cyclic operation of steam generating units.

5. Research to gain a better understanding of the responses of steam generating equipment to automatic controls, as well as the development of improved control systems.
6. Research and development of fast valving and braking to provide more reliable and improved performance of generating units with respect to transient stability and its relationship to system disturbances.
7. Improvement in maintenance techniques and procedures, and in maintenance tools, rigging, and other such equipment.
8. Better communications and closer coordination between utilities and manufacturers in the development of new maintenance-free designs.

Hydroelectric Plants

Most of the more economical sites for conventional hydroelectric projects have been developed. However, some new conventional developments, expansion of existing installations, and many new pumped storage projects are expected to provide large amounts of new hydro capacity.

The Generation Technical Advisory Committee has suggested research and development could improve the efficiency and economy of hydroelectric projects, with the following items listed for particular attention.

1. Larger turbines, generators, and associated facilities, all with high reliability.
2. Improved methods of flood forecasting, and related study of the most desirable methods of increasing spill capacity of existing dams.
3. Refined techniques for determining uplift pressures under gravity structures.
4. Dam instrumentation with remote indication for maximum safety of the public.
5. Redevelopment of existing hydro plants for units of greater capability in existing settings.
6. Improved wicket gate seal design.
7. Adaptation of slant shaft propeller units and bulb-type turbines for U.S. hydroelectric projects, including possible tidal installations.
8. Downstream water quality improvement with upstream controls.
9. Coordinated turbine and generator design to provide closer-coupled, more compact units.
10. Runner-blade coatings to eliminate effects of cavitation on base metal, and protective coatings for underwater metal structures.
11. Methods of air admission to turbines for cavitation control.
12. Methods of underwater concrete structure repair, including deep diving practices, and methods of deep-water construction for tidal projects and off-shore thermal installations.

Suggested areas for research and development related specifically to pumped storage developments are:

1. Effects of rapid drawdown and ice action on earthen dams and dikes; and temperature gradients, water quality control, and aeration requirements and methods on water in rivers and reservoirs.
2. Spillway requirements, for upper reservoirs, reservoir level control, fish protection needs and designs, and low flow augmentation requirements and methods.
3. Seepage control and the effectiveness and durability of methods of sealing reservoirs.
4. Vortex formation and suppression, loading and vibration of trash racks, and disposition of trash accumulation.
5. Flow conditions under high velocity at bends and expansions, and manifolded supply or discharge conduits.
6. Rock mechanics and related effects on tunnel and liner design, underground powerhouses, the use of mechanical moles, and the possibility of increased use of unlined tunnels.
7. Hydraulic transients, and wicket gate timing.
8. Machine-caused pressure pulsations and vibrations, transient loading on bearings

and on the electrical system, and methods of damping.

9. Development of reversible pump-turbines capable of operating at higher heads and with greater capacity, possibly with integral valving arrangements, ring gates, divided draft tubes, and governor control, and possibly capable of field fabrication.
10. Methods of starting from stand still, from spin mode, etc. and timing and control in various modes.

Gas Turbines

The unique characteristics of gas-turbine generator units have given them a useful place on many systems, and many have been installed in recent years to provide emergency and peaking power. As system sizes increase, however, it is anticipated that gas-turbine units as large as 300 megawatt will be needed. This may demand resolution of some of the problems now limiting maximum size, or it may require combining gas-turbine units with other generating apparatus. In addition, considerable R & D is needed to minimize maintenance costs which in some cases now appear to be excessive when compared with other methods of generation. Finally, it is hoped that heat rates of 10,000 Btu per kilowatt-hour or better can eventually be attained.

The use of less expensive fuels has been proposed for gas turbines for more than 20 years with little apparent progress. Improvements in this area would, of course, increase the attractiveness of gas turbines for electric utility application.

A few experimental installations of combined gas turbines and steam cycles have been made, but none has demonstrated significant overall economic or operating advantages over conventional steam-electric power plants.

Steam and water injection in a gas-turbine cycle provides potential for development if restrictions on use of water can be avoided in the location of power plants or accommodated in the design of future installations, and if problems associated with water purity can be resolved.

The use of gas turbines utilizing the output of gas-cooled nuclear reactors is receiving increasing attention, and may offer a potential for future gas-turbine applications.

Many gas-turbine installations have provisions for remote starting and loading and almost unattended operation. Starting reliability has been fairly high, but dependence on this type of unit for emergency service has presented some risk, because failure of a unit to start, for example, is a problem that usually cannot be resolved remotely.

Audible noise has sometimes been a deterrent to installation of gas-turbines in some locations and could become a greater problem with increasing unit sizes. Muffling and other noise suppression measures have been relatively effective, but further improvement would be helpful for future equipment of this type.

Current needs, some of which are subjects of present research and development efforts in the gas-turbine field, include the following principal areas:

1. Improvements in materials—particularly in high-temperature, high-strength, corrosion-resistant alloys.
2. Improvements in combustion chamber design to increase combustion efficiency, afford better temperature control, and minimize air pollution.
3. Improvements in air intake and exhaust designs to reduce noise levels and minimize pressure losses.
4. Improvements in overall design to increase unit output.
5. Upgrading of control and monitoring systems to increase automation and improve operation.
6. Combination of gas-turbine and steam cycles.
7. Development of methods of burning heavy distillate oils that are low in sulfur and metallic substances.
8. Development of higher capacity units.

Diesel Plants

The ability of diesel units to assume full load within about one to three minutes from a cold start makes them one of the most quickly available of all prime movers in use by utilities today. This is a significant advantage, but many systems need higher capacity diesel units than those now available to satisfactorily meet their peaking and emergency services requirements.

Possible New Methods of Power Generation

The new concepts of power generation that have received the most serious consideration are magnetohydrodynamics (MHD), fuel cells, thermo-electrics, electrogasdynamics, thermionics, geothermal systems, controlled thermonuclear fusion, and solar energy conversion. Descriptions of these possible methods of generation are given in chapter 9.

Although the feasibility of small-scale MHD power generation has been amply demonstrated, extrapolation to even prototype central station power plants appears to pose a number of difficult engineering problems needing extensive research. An MHD arrangement which could be used with a nuclear fuel source requires an extremely sophisticated reactor and appears to be far into the future. Although some backers of chemically fueled MHD experimental work are enthusiastic about its application to utility power plants, the Generation Advisory Committee is less optimistic about its development for practical and economical utility use.

The Office of Science and Technology in 1969 recommended to the Executive Office of the President that the Government encourage further investigation of the coal-burning, open-cycle, gas MHD system. It recommended proceeding with a research and development program directed toward solving some of the problems of such systems as a prelude to proceeding with a full-scale prototype MHD demonstration system. It further recommended a program structure such that the power industry and suppliers would contribute financial support approximately equal to an annual Federal Government contribution of about $2 million over a three-year period. The promise of improved efficiency in fossil-fuel combustion warrants an expansion of research in MHD. Some industry representatives believe that study of liquid metal MHD should be carried on simultaneously with the plasma MHD programs.

Considerable interest has been shown in fuel cells for industrial and residential use. The fuel cell's freedom from moving parts, its freedom from the Carnot efficiency limitation, and its minimal effect on the environment make it attractive. If current efforts to develop fuel cells for industrial and residential use are successful, and if an adequate supply of natural gas or other adequately processed fossil fuel is available at a competitive price, fuel cells could make dramatic changes in the electric power industry. Information concerning the present technology and ongoing research and development programs appears in chapter 9.

The electrogasdynamic (EGD) process involves severe insulation problems because of high gas temperatures combined with extremely high voltages. The present outlook for development of a practical EGD generator for electric utility use does not seem promising enough to justify major research effort in the immediate future.

Thermoelectric devices are used rather extensively for small, isolated, and portable power sources. The generators appear to be limited to about 10 percent efficiency, however, and their use for central power stations is so unlikely that extensive research by the power industry does not appear to be warranted.

The development of thermionic generators suitable for power plant application involves unfulfilled requirements for satisfactory materials to serve as high temperature emitters for high power thermionic devices, close tolerance fabrication, and suitable electrical insulators.

In the United States modest expansion in the limited use of natural steam from geothermal sources to drive turbines for power generation is planned. However, there are other geothermal possibilities which appear to merit further R & D. One involves the use of nuclear explosives to form cavities in hot rock formations which could be used to produce superheated steam for power plant use. Another involves a thermal conversion process, known as Magmamax, which utilizes medium-temperature hot water from geothermal wells to flash isobutane in a heat exchanger for propulsion of a gas expansion turbine. Successful development could lead to the use of many geothermal areas now considered marginal because of their low temperatures.

In the long run, thermonuclear fusion presents very attractive possibilities. The Atomic Energy Commission, as well as a group of investor-owned electric utilities, are supporting long-range research programs aimed at controlling such reactions for the production of electric power. The accomplishment of this goal has been described as one of the greatest scientific and engineering challenges of our time. From

the present work, which is directed primarily to a demonstration of the feasibility of sustaining a controlled thermonuclear reaction, the research projects look far ahead to the design of a containment structure which can successfully withstand the extremely high temperatures and control the nuclear radiation associated with plasma at several hundred million degrees Centigrade, drawing heavily on cryogenic technology to achieve the high field strengths required. Electric energy may be taken directly as dc by collecting charged particles released from the containment, or by generation in a more conventional cycle using the heat released to make steam. In addition to the plasma physics technology which must be developed, there are numerous engineering and applications problems to be solved.

We support continued research in this area and recognize its potential and importance as a virtually inexhaustible energy source for the long-range future.

Solar energy conversion systems are often suggested, but none has yet been developed as a practical source of bulk power. The amount of energy available makes it an attractive power source, and it may be harnessed, through thermal conversion for limited commercial use within 10 years.

Fuels and Fuel Transportation for Power Plants

Many of the problems concerning fuels for the Nation's power plants are those of pollution and other environmental effects, and any discussions of fuel and the environment are somewhat

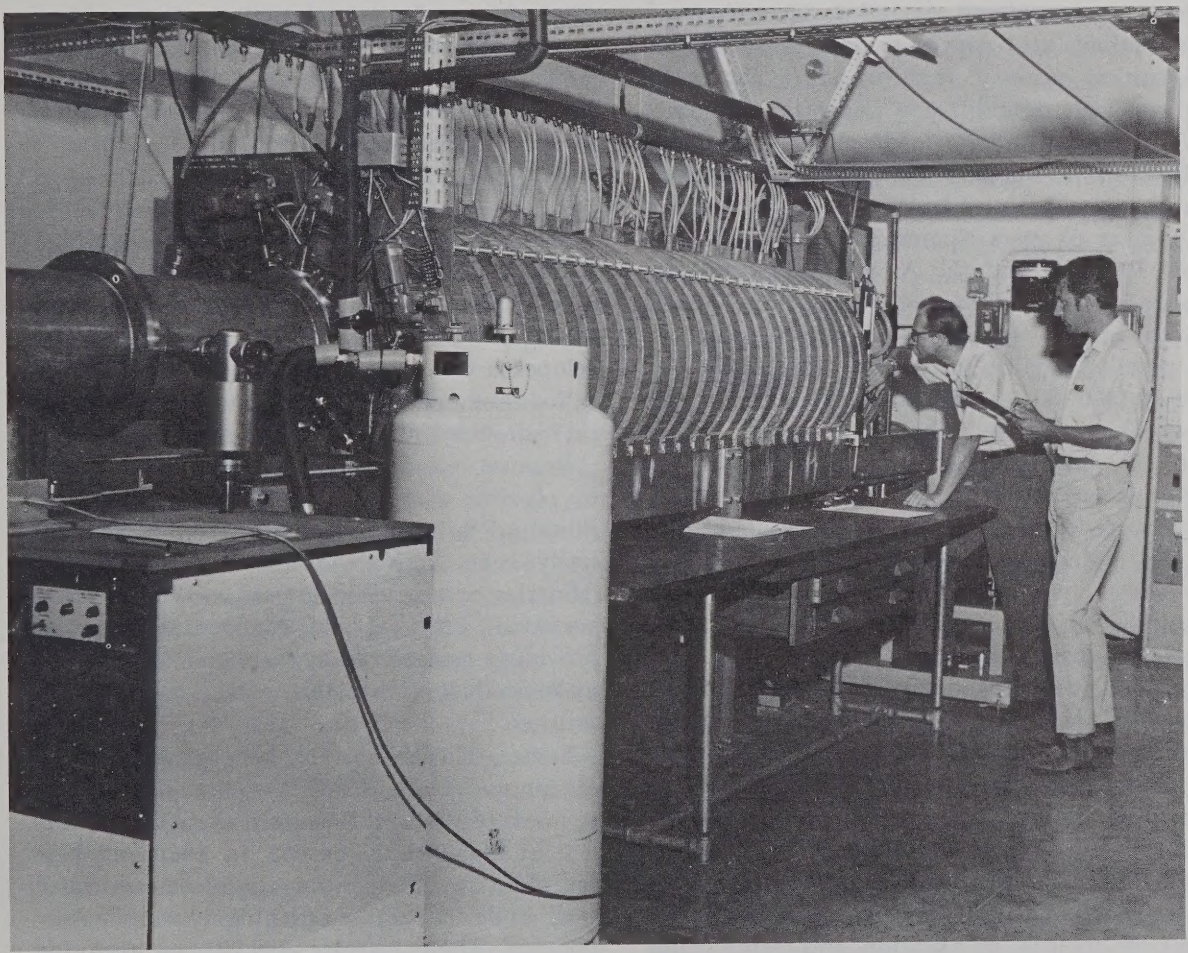

Figure 21.6—New methods of confining deuterium gas at the ultra-high temperatures needed for thermonuclear fusion power generation are being sought in this experiment of the University of Texas at Austin.

difficult to separate. Nevertheless, this section is intended to discuss research and development pertaining to fuel only. Environmental considerations, although closely related in some instances, will be discussed in a later section of the chapter.

Coal

Coal is expected to continue as a major fuel for electric utilities throughout the foreseeable future. Although its use as a percentage of total fuel requirements of electric generating plants is expected to decrease, its overall use in tons will increase. Therefore, in view of present environmental concerns, the need for coal treatment to enhance its quality, modify its form or otherwise improve it for use as a power plant fuel is greater than ever.

Some research to reduce the sulfur content of coal, such as research on solvent refining and coal gasification, is under way. It should be continued vigorously and expanded. Since much of the Nation's coal supply is high in sulfur, an economical means of reducing sulfur content is an extremely desirable and important objective.

The research efforts to develop an economically feasible method of producing pipeline quality gas from coal have been in progress for a number of years. Sponsored by the Office of Coal Research and the American Gas Association, a pilot plant, capable of processing 75 tons of coal per day to produce 1.5 million cubic feet of pipeline quality gas, was completed in the fall of 1970. The successful development of viable coal gasification technology could be valuable, not only in increasing the availability of clean power plant fuel, but also to facilitate its transportation from coal fields to points of use. If the underground transformation of coal to the gaseous state should prove practical it could reduce mining operations and their attendant land disturbance problems.

Washing and other methods of coal cleaning have also been the subjects of research efforts to make it a more pollution-free fuel. Development of methods for the economical removal of pyritic sulfur and non-combustible matter is needed, and continued efforts are warranted.

Solvent refined coal is the product of a process that dissolves raw coal in a solvent, separates the ash from the coal by filtration, and reconstitutes the coal from the solvent. The reconstituted coal is free of water, low in sulfur, very low in ash, and sufficiently low in melting point that it can be handled as a fluid if desired. In its solid state it is brittle and readily ground into a fine powder. Its heat content is elevated over that of coal to a uniform value of 16,000 Btu per pound, regardless of the original coal from which it was processed. Its unique characteristics make it attractive as a boiler fuel consistent with expected air pollution restrictions on the emission of sulfur and particulate matter in many areas. The potentials of the process suggest that pertinent R & D should be increased.

Unit train arrangements, pipeline slurry facilities, and other means of conveyance have been used to satisfy some of the ever-increasing coal transportation needs. However, with increasing coal requirements and more congestion in areas of high population density and industrial concentration, transportation is still a growing problem which merits accelerated study to provide satisfactory solutions.

Mining methods and techniques, mine safety, land restoration procedures, and related new equipment development appear to be appropriate areas for increased R & D study.

Oil

Much of the world's supply of petroleum has a high sulfur content and, therefore, presents some of the same problems encountered with high sulfur coal. The refining industry has developed a technology for removing much of the sulfur from residual fuel oil, but more economical hydrodesulfurization processes are needed.

Because it could not be moved economically by pipeline over long distances, past use of residual oil for electric power generation has generally been limited to areas near petroleum refineries or accessible to low cost water transportation. Practical and economical means of providing transportation to inland areas would make residual oil available to many more electric utilities.

Some attention has also been given to crude oil for use as a boiler fuel. Again, with respect to much of the world's supply, there is the problem of high sulfur content. In addition, there are often special handling problems associated with crude oil because of its highly volatile components. These increase the risk of explosion and fire. Nevertheless, there may well be situa-

tions in which crude oil would make a desirable boiler fuel. Therefore, continued work by those interested in adapting it to such use is merited.

Because of the projected large increase in demand for liquid fuels in the years ahead, there has been growing interest by government and industry in oil-shale resources to supplement crude petroleum reserves. Oil-shale resources of the United States are extensive. Therefore, in view of the limited availability of other energy resources and the increasing use of energy, research is needed to identify the best methods for long-range development of oil-shale deposits.

Natural Gas

Natural gas, because of its cleanliness, and ease of transmission, and because it does not require complicated and expensive handling facilities, is a highly desirable fuel for power plant use. Except by reason of cost competition from other fuels, the use of gas for boiler fuel is limited largely by its unavailability, particularly in some locations and at certain times of the year when it is in high demand for space heating and other seasonal uses.

Results of the initial experiments using contained nuclear explosions to enhance the recovery of natural gas from low-permeability gas formations are encouraging. Although evaluation of two such projects, Gasbuggy and Rulison, may not be completed for some time, present information indicates sufficient success to justify continued research in this area.

Liquefaction of natural gas has recently become more prominent. The process was first used as a relatively convenient means of natural gas storage to supplement volumes of peak gas available at times of from traditional sources in particular areas, but recent trends have suggested the probability of much wider use of liquefied natural gas (LNG) in the future. There are possible problems, however, and some concerns about safety. Although transporters of LNG have excellent safety records, little is known about the behavior of LNG in the event of large spills. More research would be valuable in establishing the behavior of LNG in the event of spills.

It has been suggested that the heat absorption accompanying the change of LNG from the liquid to the gaseous state might be utilized advantageously in a generating plant to cool condenser discharge water, thereby reducing thermal effects on natural water bodies.

Nuclear Fuels

The manufacture of nuclear fuel for light water reactors involves the conventional steps of mining and milling uranium, and refining, enriching, and fabricating the fuel before it is placed in the reactor for energy production, and reprocessing the fuel after energy production to recover unused fuel. These operations provide a broad scope for R & D efforts.

The fuel material handling and processing requirements of light water reactors using uranium are relatively well established. However, there are ongoing R & D efforts directed toward improved fuel design (particularly improved performance of cladding and increased burnup), better spent fuel shipping techniques, the reduction of by-products in the spent fuel processing step, and improved ways of handling and storing fuel wastes.

An important area of R & D is the development of a way to use fissile plutonium as a substitute for uranium in light water reactors. In addition to the anticipated need for plutonium recycle with the present generation of reactors, it would appear to become even more important if development of the breeder reactor is delayed beyond present expectations.

R & D efforts required in the development of the Liquid Metal Fast Breeder are extensive. Key areas include research to ascertain the effects of fuel cladding irradiation, characterization of both oxide and mixed carbide fuels, and accumulation of physics data to improve sodium void and Doppler coefficient calculations. Other related areas include development of reliable and accurate instrumentation and reprocessing techniques.

Another possible nuclear fuel is thorium. However, unlike natural uranium, thorium has no fissile isotopes. Therefore, the initial fuel inventory and any makeup fuel required to sustain the operation of thorium cycle reactors will depend upon supplemental fissile material. The recycle of fissile material (U–233) produced in the thorium cycle poses some difficult problems. The research and development efforts necessary to insure the economic use of thorium span the whole field of reactor technology. If the application of thorium fuels becomes more widespread,

additional research and development will be required not only for reactor construction and operation, but also for fuel reprocessing and fuel refabrication.

Environmental Considerations

The electric power industry has for many years recognized the need to minimize pollution and other adverse environmental effects of power facilities, and has exercised various control measures. These measures are being greatly expanded, however, to meet the increasing demands of the public and governmental agencies concerned with environmental quality.

Air Pollution

Particulate Matter

There has been continuing development of equipment to remove particulate matter from stack gases, and highly efficient devices are now regularly used in modern plants for particulate control. Despite the progress which has been made, however, there is need for research to further improve the efficiency, reliability, and long-term performance of electrostatic precipitators and to develop methods for performing maintenance without waiting for unit outage. There is also a need for research on filters and scrubber systems for fly ash removal as possible alternatives to electrostatic precipitators.

Neither a precipitator nor any other removal process will be able to operate satisfactorily unless a reliable and effective method exists for handling and disposing of the fly ash after it is collected. As an adjunct to programs for fly ash removal and handling, many efforts have been devoted to the development of its economic use. As a result, fly ash is used as an additive in mixes of concrete and asphalt, and fused granules from wet-bottom furnaces are used in coating roofing shingles, but the supplies will exceed demand unless other uses are found.

Sulfur

During the past several years, considerable effort has been devoted to the development of practical means of removing sulfur pollutants (particularly sulfur dioxide) from stack gases. Several prototype installations have been put into service, but so far none have provided a completely satisfactory answer to the problem. Simpler and less costly means of accomplishing the pollutant removal are needed. Other approaches are under investigation and new demonstration facilities are under construction. While the Office of Air Programs—EPA, formerly the National Air Pollution Control Administration, has sponsored many of the major research projects in this area, some individual utilities and industry groups have more recently increased their participation markedly and are now sponsoring significant research and development programs. Industry group efforts include a multi-million dollar joint project of the Electric Research Council and the National Coal Association.

Similarly, some work has been done concerning the removal of sulfur from fuel before combustion. This includes research on fuel gasification processes. For example, interest has been expressed in a concept utilizing both pipeline gas technology and combined gas and steam turbine technology. The concept involves a fuel gasification and desulfurization process similar to a pipeline gas process, but without the methanation and possibly using air rather than oxygen. The objective would be to produce a high pressure, low Btu gas suitable for gas turbine fuel. The process would result in essentially complete sulfur and particulate removal, would greatly reduce thermal pollution relative to a conventional steam cycle, and would offer possibilities for nitrogen oxide control. Such a combined gas-steam pilot plant (170 megawatts$_e$) is under construction in West Germany.

Nitrogen Oxides

Nitrogen oxides produced by power plants are primarily the products of reactions between the oxygen and nitrogen in the air that supports the combustion of fossil fuels. The quantities produced are primarily a function of furnace temperatures and quantities of air introduced to maintain efficient combustion. Satisfactory technology for the removal of nitrogen oxides from power plant flue gases is not available. Some R & D is under way but a more intensified effort is needed to assure compliance with the stringent air quality standards which are being enacted. At present, control of nitrogen oxide emissions is accomplished by limiting the formation of the oxides in the furnace through modification of the combustion process. Such modifications frequently lead to reduced boiler efficiencies.

Radioactive Releases

Measures to assure reduced release of radioactive materials into the atmosphere at both fossil and nuclear fueled plants are being demanded. The control of gaseous radioactive material at nuclear plants is discussed further in chapter 6.

Although not limited to air pollution which is the general subject of this section of the chapter, a problem of major significance is the release of waste radioactive materials in the processing of spent nuclear fuels. In addition to any releases into the atmosphere, there are the radioactive liquids and solids which present problems.

General

Aside from the work devoted to reducing or eliminating known air pollutants, it has been suggested that research effort be directed to improved means of identifying all undesirable pollutants and their sources, and predicting pollutant concentrations.

There is also a need for better techniques of measuring the concentration of submicron and larger particles in flue gases, and research to meet this need is appropriate.

In addition, little is known about the probabilities of undesirable physical and chemical reactions due to the mixing of flue gases and water vapors which might occur where large steam plant stacks and cooling towers are in close proximity. Research on the associated environmental effects is warranted. In addition, studies of the effects of cooling tower plumes on dispersion of power plant stack emissions are also needed.

Water Ecology Studies

Current research efforts on the ecological effects of heated water and on means of dealing with related problems include studies by government agencies, universities, utilities, and consultants. A large number of extensive studies completed or under way deal with such topics as the effects of: changes in water temperatures; thermal inputs on biological life; power plant operation on overall water quality of an estuary; changes in the ecological community structure as a result of increased water temperatures; heated water on oyster, shrimp, lobster, and catfish propagation and growth rates; and condenser water discharge in large lakes. Some of the studies involve changes over time and space and include extensive river systems. An example is the Connecticut Yankee study. It is now in the sixth year of a seven-year program designed to compare the ecology of the Connecticut River before and after commercial operation of a large nuclear power plant. The importance of such studies cannot be overemphasized because of the value of estuarine areas as nursery grounds for salt water shell and fin fish. Other examples of major ecological studies now in progress are those related to Lake Michigan.

There is a need to determine more precisely the thermal ranges required by all important species of fish and other aquatic organisms, as well as the "biological" cost of progressively increasing temperatures. This would permit selection of the temperature criteria necessary to preserve desired species. The information needed includes the maximum temperature at which normal body functions, including growth and reproduction, can occur; determination as to whether seasonal low temperatures are necessary to stimulate sexual activity and maturation of eggs and sperm; temperatures which will otherwise be unattractive (or attractive) to various species of fish; the effects of temperature on disease in fish; the relation between temperature and competition and predation among food chain organisms; the effects of temperature changes on algal and bacterial growth; and the range of allowable temperature fluctuations. Such information should indicate how much of a river or reservoir area is pre-empted by the heated discharges of a particular plant from use by various species of aquatic life.

Much useful information has been gained from studies already completed, but further studies are needed for a better understanding of the movement of heated water in reservoirs and streams so that the magnitude and extent of its effects can be determined. Data are needed on the time required for diffusion of heated water into a water body and on the upstream movement of heated water in flowing streams. Studies should be made on the effects of various types of channels on heat dissipation. Studies are needed on means of optimizing the use of mixing zones. Means should also be developed to make predictions concerning the stratification of heated water in reservoirs, including a determination of the interface friction between a warm

water wedge and a lower layer of cold water. More precise data should be obtained on the effects of atmospheric conditions on evaporative and convective heat losses. The effect of temperature rise on the sediment transporting capability of streams should be investigated. There should be further research to improve the ability to make water temperature predictions for use in determining the impact of heated water discharges. This requires improved procedures for utilizing local meteorological information in various parts of the country and less reliance on generalized coefficients.

Cooling Water Systems

Some recent steam-electric plant designs have used supplemental cooling or water diffusion systems to reduce the quantities or increase the mixing rate of heat rejected into natural bodies of water. More recently, concern has been expressed about even very small changes in the temperature of streams and other natural water bodies. The combination of increased unit size and the stringent water quality standards being suggested makes it impossible in many instances to use conventional once-through cooling methods with water subject to these standards. There is a pressing need for new methods and new approaches to the dissipation of the heat in condenser cooling water. It is hoped that some of the current Government and industry sponsored thermal pollution studies, such as the Heated Water Discharge Research Project of the Edison Electric Institute, will provide the criteria needed to protect water quality.

Cooling towers are likely to be utilized in many new power plant installations. Therefore, their own unique effects on the environment must be investigated thoroughly, including the effects on nearby substations and transmission lines. With wet-type cooling towers, the major environmental concerns have usually been the effects on local weather of both massive heat discharges into the air and enormous quantities of water evaporated into the air at one point. As mentioned before, studies should be made to determine the interaction of this water vapor with other pollutants in the air. In addition, the studies should include the environmental effects of chemicals used in the water spray to control organic growth and in periodic blowdowns to remove soluble chemicals and other solid residues left by evaporation. There should be investigations concerning the use of brackish or other poor quality waters for cooling tower makeup supplies; if the results are favorable power plant siting could become more flexible.

The characteristics of dry-type towers justify concerted R & D effort to produce designs and arrangements suitable for use with large scale power plants. While they, too, produce highly localized, massive heat discharges into the air, they do not result in the evaporation of large quantities of water. It has been suggested that design studies should be made of the generating plant and dry tower as a unit with consideration to cycle improvements and waste heat reduction as integral objectives. Use of supplemental sprays during adverse climatic conditions should be studied with a view toward reducing costs and minimizing tower sizes. Optimized heat transfer designs and arrangements should also be studied. Construction of a demonstration model at an early date is desirable.

Aside from cooling towers, there are other heat disposal systems. Artificial cooling ponds are a notable example. They appear to cause the fewest adverse effects on the natural environment, and in many cases may offer distinct benefits to it. However, they require large land areas which are not always readily available. The effectiveness and desirability of using supplemental spray ponds at large plants where land is limited should be investigated. Still other heat disposal systems offer possibilities to make use of waste heat in industry, agriculture, and aquaculture. The relatively low temperature of cooling water limits its adaptability to heat-transfer uses, but some potentials do exist. These include the use of waste heat for process or space heating and cooling, for improving the biological efficiency of sewage treatment plants, and for increased agricultural production. The use of reservoirs at hydroelectric plants offers a possible means of regulating river systems for improved water quality and dissipating waste heat produced by downstream steam-electric plants. Multi-level outlets in the reservoirs of such systems could be used to control the temperature of released water.

Finally, radioactive discharge into the cooling water systems of nuclear power plants have been a highly controversial issue during the licensing procedures for several new plants, even though

radioactive releases to the cooling water at operating nuclear plants have been, on the average, only a few percent of AEC limits, which were based on recommendations of the Federal Radiation Council, the National Council on Radiation Protection and Measurements, and the International Commission on Radiological Protection, among others. On June 4, 1971, AEC issued a proposed rulemaking which sets forth proposed numerical guides to keep levels of radioactivity in effluents to unrestricted areas as low as practicable. Under these guides, radioactivity released from light-water-cooled reactors would generally be less than five percent of average exposures from natural background radiation. This level of exposure is about one percent of Federal radiation protection guides for individual members of the public.

Power System Reliability

There is no question that the power systems of the Nation provide reliable service, and that the average customer has electric power available an extremely high percentage of the time. Despite this high average, however, some outages do occur, and since any are costly, and extensive ones can be harmful in some respects, every effort must be made to minimize outages, their duration, and effects.

One of the industry efforts toward meeting this objective is the Electric Research Council's current research project, "Improved Operational and Control Methods for Bulk Power System Security."

The results are expected to aid materially the operation and control of future power system networks and to provide a basis for still further development.

The Electric Research Council project encompasses six different areas of interest with six different investigating groups. The areas of study are: (1) methods and means of on-line stability analysis of power systems; (2) feasibility and requirements of a combined analog-digital computing system for faster solution of power system transient stability problems; (3) system security assessment by simulation approach; (4) system security assessment by probability approach; (5) effective equivalent representations of large interconnected system networks; and (6) a generalized approach for determining optimal solutions to problems involving system security and savings. The initial phase of this work is completed, including reports of the investigating groups.

Better simulation models for predicting electric phenomena could facilitate design of EHV and UHV systems for greater economy and reliability. Analytical means for predicting harmonic and total voltages during steady-state conditions would be an asset in designing future systems. Better mathematical representation of such variables as the nonlinear elements of a polyphase alternating current power system, untransposed lines, and the possibilities of insulation breakdown during voltage surges could help solve many design and reliability problems associated with both normal and abnormal system conditions. The utilities, some educators and consultants, and electrical equipment manufacturers are working to improve problem solution methods and computational techniques, but better answers to many problems are still needed to provide for adequate analysis, system planning, and design of future power facilities. There is an overall need for improvement in relating transmission system planning to reliability of service.

Some utility engineers have pointed out that as generating units become larger, the problems of stable system operation become greater and there are needs to investigate gains which might be possible through faster switching, ways of allowing brief asynchronous operation (such as the two-field machine), more effective excitation control, and other related possibilities.

A number of utility representatives have indicated that there is need for a high-power electrical apparatus testing facility in the United States. Such a facility would test the adequacy of design of power system apparatus. This would lead to more dependable performance of new equipment, and thus improve system reliability. At present, some utilities and equipment manufacturers utilize foreign laboratories for certain high-voltage and high-power testing of new equipment. Such a test facility has been proposed by the Electric Research Council for location near Grand Coulee Dam. Although financing of the proposed $35 million project has been a major obstacle, strong consideration of some means to provide adequate test facilities should continue.

Research and Development Priorities

It would, of course, be impossible for the electric power industry to pursue vigorously at one time all of the research and development programs discussed and suggested in this chapter. Priority decisions must be made on a continuing basis. Changes in needs call for new priorities, and in the past few years such changes have occurred with increasing rapidity.

It is apparent, therefore, that the electric utility industry—both individual utilities and utility groups—and governmental agencies must remain sensitive to trends in public concern and changing national goals, and be flexible so as to respond accordingly. To accomplish this, an ongoing forum for discussing, establishing, and updating industry priorities is needed.

At the present time, the Electric Research Council has a task force at work to recommend a program of industry research and development for the next 30 years. It has asked major electric power organizations, as well as industry groups, committees, and technical forums for their views on the immediate and long-term research and development needs of the electric utility industry. Major electrical equipment manufacturers, scientists, engineers, university staffs, Federal agencies, and others have also been asked for their views in this matter.

Another task force within the Electric Research Council is working toward establishment of a formal organization to administer the research and development program and to devise methods for obtaining the required funding. This administrative group would also be responsible, among other things, for reviewing electric research and development work to assure that a high degree of relevancy and cost effectiveness is maintained.

Meeting the Research and Development Requirements of the Future

Research and development related to the production, transmission, distribution, and sale of electric power will require much greater direct participation by the utility industry in the future than has been the case in the past. To maximize the effectiveness of such participation, all segments of the industry should coordinate their respective research and development efforts. A piecemeal approach in which each utility or group of utilities supports only its own favored research and development projects will fall short of meeting the demands of the future.

Institutional Framework

There has been much discussion within the industry as to the best institutional framework for conducting a massive, coordinated research and development effort. There is general agreement that an industry research program should be directed by a continuing, non-profit, centralized agency, administered by and representing all segments (investor-owned, cooperative, and government-owned, both Federal and non-federal) of the industry, and possessing the ability to ensure that the total research effort will be of high quality, clearly relevant, broad, and thorough without duplication of effort. There are, of course, legal and policy questions, including questions of tax, patent, and antitrust law, the answers to which will dictate the precise form of the organization and the requirements that will attach to industry funds for research and development. It would be well for the industry to identify carefully these problems and agree at an early date to a policy framework for their specific solution.

The centralized agency would be the recipient of a large share of the industry's research and development funds and would be responsible for channeling them into projects approved by its board of directors. Its major functions should be as follows:

1. Provide a continuing forum for identifying research and development needs and priorities, and formulating guidelines for industry participation, taking into consideration the industry's future performance requirements, demands on natural resources, and the environment.
2. Translate these guidelines and priorities into detailed programs that could be pursued by appropriate entities, including the industry's research organizations, government agencies, and other organizations created for this purpose by industry or government.
3. Administer its own research and development programs.

While there is substantial agreement with respect to functions of the research and develop-

ment organization, opinions are more diverse with regard to precisely how it should be established. One promising suggestion is to build an expanded organization on the framework of the Electric Research Council, possibly through incorporation, to perform new functions and meet new goals. In any event, it would seem wise to take advantage, to the extent possible, of working relationships already established within the Electric Research Council, which is widely viewed as the representative of both public and private segments of the industry on research and development matters. Nevertheless, some people believe an entirely new organization should be created to serve as the industry's central agency to organize and conduct research and development work.

Scope of Industry-Sponsored Research and Development

In general, the electric utility industry should focus its attention on the development end of the research and development spectrum. Basic scientific research is probably best left to the government and the universities and, as a general rule, work aimed at translating the results of basic research into marketable products should probably remain with the manufacturers. In this way responsibility will be placed where incentives for quality and timely performance lie. There are, however, some programs such as the development of the fast breeder and fusion reactors where the magnitude and complexity of the programs are so great as to require joint participation of all segments of government and industry, to the fullest extent possible, for successful attainment of the research and development goals.

Financing

Another important question is the method by which research and development funds can best be made available on a continuing, coordinated basis. The Electric Research Council has a task force studying the problem. It is believed that expenditures by the electric utility industry should be increased to as much as $150 million to $200 million annually to finance needed research and development (not including R & D work on the liquid metal cooled fast breeder reactor). This assumes a continuation of at least present levels of research and development expenditures by the Federal, state and local governments in areas of particular concern to them, and continuing substantial research and development expenditures by the electrical equipment manufacturers. It is important to stress that the proposed additional efforts by the utilities should be by an infusion of new dollars, and added utility contributions should not merely be a substitute for monies now being spent by government or manufacturers for research and development.

It is also important that understandings be reached among the manufacturers, the utility industry, and the government as to the kinds of research and development activities to be wholly or primarily within the sphere of each. Various Federal agencies, including the Office of Management and Budget, the Environmental Protection Agency, the Office of Science and Technology, the Deparment of the Interior, the Atomic Energy Commission, and the Federal Power Commission, should be concerned in the process of rationalizing the overall research and development effort in terms of national goals and priorities.

There are a number of possible approaches to raising the money. One of the most promising may be coordinated industry-wide commitments to make the necessary annual funds available. Participating utilities would, for example, commit themselves to contribute an amount, based upon their kilowatt-hour sales, to the research and development organization. With widespread participation, a contribution rate of 0.1 mill per kilowatt-hour of sales would raise approximately the suggested amount. Participation by a utility would assure it access on equal terms with other members to the fruits of the research and development, including rights to full knowledge of the work done and royalty-free rights to any resulting patents. One way for a participating utility to raise money for its research and development contribution might be an add-on charge for kilowatt-hours sold, a charge which could take the form of a research and development rate rider. Any such funding method would, of course, require approval by appropriate regulatory agencies. Support at the highest levels nationally would be necessary to make a voluntary funding plan work.

Another, but perhaps less desirable, approach

to the raising of money for research and development might be a publicly imposed tax on electricity sales, perhaps at a uniform rate per kilowatt-hour on all kilowatt-hours sold. It has the twin virtues that: (1) every utility and utility customer would contribute on a uniform basis, and (2) the funds would be easily and readily collected. However, there are some who fear that government control of the tax revenues might open the door to use of some of the proceeds for non-research programs, or at least might lead to research and development priorities and programs other than those which the industry feels are most pressing. If such a financing program is undertaken, full use should be made of existing utility knowledge and expertise, regardless of the organization which may be made responsible for adminstering the research and development programs.

Other possibilities for funding include voluntary contributions by utilities and Congressional appropriations such as those received by the Atomic Energy Commission. Neither of these appears to represent as reliable a source for the needed funds as the others.

As mentioned before, funding requirements for the breeder are not included in the $150 to $200 million annual research and development requirement which has been discussed. With breeder development itself expected to require in the neighborhood of $2 billion over the next decade or so, it appears that a separate financing program for the breeder should be established. Moreover, the program described above for other research and development work would probably take some time to implement—time which the breeder program cannot afford to lose.

Because of the massive funding requirement for the breeder it is certain that government and industry will have to share the burden, but the details of a specific financing program require further study. In order for work on the breeder to proceed expeditiously, it is necessary for government and industry to reach agreement on a plan very soon.

MANAGING THE POWER SUPPLY AND THE ENVIRONMENT

A Report to the
Federal Power Commission
by the
Task Force on Environment
July 1, 1971

356-238 O - 72 - 28

Honorable John N. Nassikas
Chairman
Federal Power Commission
Washington, D.C. 20426

Dear Chairman Nassikas:

We are pleased to present herewith the report of your Task Force on the Environment.

Since January 1970 the group has met a number of times, reviewing the National Power Survey data and other materials from the Commission and from many other sources. The Task Force has tried conscientiously to recognize not only the environmental problems involved in the generation and transmission of power, but also the quite obvious fact that some solution must be reached to resolve these problems if the necessary power is to be provided to the American people.

Our purpose has been to examine and to characterize those considerations which the Task Force felt to be of major significance in finding the proper balance of public interests in this area. In so doing we have not endeavored to repeat herein any detailed suggestions for siting of plants and transmission line rights-of-way as reviewed by others.

This report represents a consensus of the Task Force. We are grateful to have had the opportunity of looking into this matter.

Sincerely,
M. Frederik Smith, Chairman

Joseph J. DiNunno	Byron O. Lee, Jr.
Dr. Rolf Eliassen	Dr. John T. Middleton
S. David Freeman	Dr. Donald I. Mount
Dr. Frank E. Gartrell	Richard H. Stroud

FOREWORD

In January 1970 the Federal Power Commission established a special Task Force on the Environment to assist in the preparation of the National Power Survey of 1970. This Task Force was asked to assess and report independently to the Commission its views on the present and future environmental aspects of electric power supply in the United States. Following extensive reviews of the Power Survey materials and other pertinent studies, the Task Force prepared the following report of its views directed to the Commission.

The Federal Power Commission is greatly appreciative of the probing effort and thoughtful analysis of the Task Force on Environment and commends these views to the full attention of its staff, to the electric power industry, those with official responsibilities in this area, to consumers of electric power and to all other concerned citizens.

John N. Nassikas
Chairman

John A. Carver, Jr.
Vice Chairman

Albert B. Brooke, Jr.
Commissioner

Lawrence J. O'Connor, Jr.
Commissioner

Pinkney C. Walker
Commissioner

October 1, 1971

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Introduction

During the past few years, concern for the environment has emerged as a major, if not a controlling, factor in the nation's supply of energy.

This relatively new environmental thrust has been fueled by the belated recognition that we have paid dearly for our national devotion to energy availability and efficiency as basic sources of our national progress. The environmental price paid for our energy supply sometimes has been incalculably expensive: the careless strip mining of coal, the spillage of oil in the ocean and on beaches, the sometimes careless routing of pipelines through scenic areas, the neglect of measures to control the waste products of fossil fuel combustion, some of the end uses to which energy is put, and perhaps most obvious of all, the environmental impacts of electric power generation and distribution.

Electrical power, the most universal energy form, has been promoted as a national policy. A compelling consideration in the past has been the need to deliver it at the least possible cost to the consumer, and this position also has been a national policy. It has been encouraged by the federal government, and enforced in most states by Public Service regulating boards. It has been the essence of utility promotion, and progressive economies are expected by consumers. As a result, generating plants traditionally have been built in convenient and economical places, in many cases without adequate thought for the environment. Plants often represented the ultimate in functional architecture: no nonsense, as little aesthetic design as feasible, as few extras as possible in the way of amenities. Often they were factories for cheap power, although some progressive companies considered design as long ago as two decades. Transmission lines normally ran over the land in the most direct path, often at the sacrifice of environmental assets, and the relatively few complaints went unnoticed, for this procedure contributed to cheap power, an objective set in an era when smokestacks were regarded as desirable evidences of prosperity and progress.

In our time, we have seen commanding new social values arise, and among the most important of these is a new respect for the conservation of the environment, and the need to adapt our energy sources and supply to the restrictions this imposes upon us.

The mind-set of today is one that accepts environmental problems as very real ones, and that industry should not only cooperate in solving them, but should take the initiative in minimizing the release of effluents, developing practical ways for undergrounding transmission as well as distribution lines, and in achieving better architectural treatment of facilities. The industry should be more aggressive in promoting environmental protection. Consumers must be warned, however, that they must pay the bill. The electric power industry should take positive steps to avoid wasteful use of electricity by consumer education and working with appliance manufacturers and building contractors to increase the efficiency with which electricity is used at the point of consumption.

This Task Force is convinced that the industry as a whole—public and privately-financed utilities alike—should move far faster, with more direction and determination. The Task Force urges, as one of its most important recommendations, that the electric utilities take firm leadership in resolving environmental problems, in accordance with standards set forth under law by responsible environmental protection agencies, and by moving rapidly to employ all possible technology to achieve this necessary goal. The Task Force also recommends that the Federal Power Commission and the utilities should insist that the state regulatory agencies face squarely their related responsibility by recognizing that the cost of environmental safeguards is a necessary element in the cost of producing electricity.

Some of the restrictions we face in the generation and transmission of power are, to say the least, troublesome. All add to the cost of producing power. Many present challenges strain technological capacity; the state of the art in some cases is not yet equal to the unquestioned need for accommodation. Yet, under the presently accepted policy, environmental standards are being set, and must be met. Environmental trespasses must be recognized and avoided. Despite these added new factors, ways must be found to provide the necessary power within the necessary environmental restrictions. What that necessary amount will be is very difficult to ascertain, and is complicated by both the changing goals of society and the availability of utilizable resources. Chapter 3 of the 1970 Federal Power Commission National Power Survey discusses ranges of power projections in detail.

The consequences of a serious power shortfall to the country, to its people, and to the economy could be most serious if it should persist for any length of time. It would greatly inconvenience and in some instances even endanger consumers. It would slow the productive capacity of the country. It would throw a wrench into the operation of our cities and our economy—for two-thirds of all power produced is used for community, commercial and industrial purposes. Therefore, there must be dependable, adequate and reliable supplies of electric energy where and when it is needed.

At the present time, a number of factors in addition to environmental demands pose major threats to the power supply of the nation.

This threat of shortage results from, among other causes, the necessity to stretch out plant construction programs because of design changes, technological advances, regulatory reviews, equipment delays, labor difficulties, material and equipment faults; it simply takes longer to get new plants into operation. Experience indicates that one reason for delays is poor workmanship in equipment manufacture, resulting in undependability in the early years. Operational problems arise increasingly from shortages of fossil fuel supplies or equipment failures —this last due partially to the new demands required of larger and more complex facilities. Inadequate anticipation of rapidly increasing electrical demand has created delay factors. Finally, there have been deferrals or stoppages of project plans or of operations as the result of objections, on environmental grounds, from citizen groups.

This last, this vigorous and effective resistance to plans or proposed plans for new electric power generating and transmission, is sometimes soundly based on unacceptable environmental threats resulting from neglect on the part of utility managements to take needed and available precautions in environmental matters. Sometimes it results from a change in official air or water standards after construction has reached a point where immediate adaptation is impossible. Sometimes it grows out of a lack of

public confidence in agencies reviewing the project; sometimes a conviction that there has been no responsible review of environmental factors. Sometimes, unfortunately, it results from self-interest or unwarranted interference on the part of protesters.

Thus, as far as public participation is concerned, we have a situation that covers a whole spectrum of difficulties: in the broad center is the range of reasonable, valid environmental objections, and unintentional violations of new or poorly defined environmental regulations, both of which may cause temporary stoppages, but both of which should be—and generally are—subject to remedial actions with minimum delay. At one extreme we have the stubborn managements who may feel that "this, too, will pass" if the present storm can be weathered; and at the other extreme we occasionally have citizen groups who may very well be exploiting the new environmental consciousness for their own purposes. Occasionally, there are public agencies in the middle that do not command public confidence.

This Task Force has endeavored to inquire factually into the nature of the present Environment-Power Supply crisis: to review the potential power demand and assess future influences on it; then to examine the environmental aspects of the supply situation and ascertain what policy action might bring about a sensible, reasonable resolution of the environmental conflict.

I. The Future Demand for Power

Energy is the keystone of civilization in our time. Electric power, certainly a major form, should be considered in the light of total energy requirements, the utilization of resources, and the demands on the environment.

The operating of elevators in our increasingly vertical cities, the processing of food in vast quantities, the powering of rapid transit, the advancing of techniques in hospitals that tends to make them electrical marvels (and wholly power-dependent), the mobility of the population, the handling of solid and liquid waste, the dependence on home appliances—these are random evidences of our increasing and—certainly to a large extent—inescapable dependence upon electrical power sources. The fact that electrical power is our most convenient and ordinarily our most available energy source places it at the very center of our society.

Traditionally, there has been no limiting factor in the availability of power for industrial purposes, nor in meeting the appetite for home comforts and conveniences. There has been nothing to arrest expansion. As a result, the demand for electrical power has grown at a rate in excess of six percent per year, about thirty percent of which has been for residential use.

This national policy of encouraged and uncontrolled growth is now being questioned, in view of the environmental toll involved in the growing industrialization of the nation and in the generation, transmission, and, in some cases, the use of electrical power. The ramifications of this changed policy are many. For example, there has been intensification of the search for new non-electric sources of energy—new ways to use fossil fuels, energy from the sun, improved atomic sources. Given enough time, money, and research, breakthroughs are possible, and in some cases likely. At the same time, numerous investigations are being directed toward new ways to generate electrical power—some, perhaps, with far fewer environmental consequences. In view of the need and the consequences, these efforts are far too poorly financed.

The pollution control facilities required in all new and most existing plants are costly, and will inevitably raise the cost of producing electricity, and rates will rise. It is reasonable to assume that this increased cost to the consumer may to some extent lower the demand for electricity.

This may be offset, however, by environmental factors, plus limitations on supply, which are raising the price of competitive forms of energy even faster than the anticipated increases in electrical power. This might well increase the demand for electricity in spite of added costs.

It might be assumed that the presently decreasing rate of population growth could be counted upon to reduce the expansion rate of electrical power to demand below rates experienced in the past. But offsetting this will be the impact of increasing family income and rising standards of living, which could increase per capita consumption of power and of goods, possibly sufficiently to more than offset the population trend.

Some reduction in power demand might result from environmental pressures or power shortages, forcing a curb on marketing activities on the part of utilities. This is especially true in such areas as climate control and industrial processes, where electric utility marketing programs and techniques in the past have included promotional step-down rates, special installation allowances, financing arrangements, and commission selling. Some utilities already have instituted curbs on such activities, though it is by no means an industry trend.

Tending to increase consumption, however, is the probable resumption of a housing program of such size as is needed. The creation of housing consumes large amounts of power, as does the maintenance of housing once it is erected.

In addition, environmental requirements themselves may place strains on the power supply. Hundreds of sewage disposal plants, heavy users of power, will have to be built; solid waste systems may turn out to require substantial power.

In spite of all practical efforts to curtail unessential uses of electrical power—and there should be such efforts, both for environmental reasons and because it seems certain we will find ourselves in a power squeeze—there is likely to be, on balance, a large increase in the total demand for power in the future. Any reductions achieved by regulation, higher prices, reduction in marketing incentives, or urge to conserve are unlikely to prove sufficient to offset new demands for energy, particularly in the commercial, industrial and governmental areas. All current surveys of the Btu requirements on a national and world basis point to continued growth during the next few decades as the result of the increasing mechanization of society and the irresistible thrust to replace human energy with mechanical energy. Btu consumption charts since 1800 have gone steadily upward without a break, except in the depths of the great depression of the thirties, and there is little reason to expect any important change.

The question now is how this growth—whatever the amount—can be met with a minimum and fully acceptable impact on the environment. Such environmental effects will manifest themselves in the electric industry's planning in a number of areas—air, water, thermal, radiological, aesthetic and land use.

Air Pollution Control is not new to the power industry. Consideration of particulate pollution has long been a factor in planning electric generation facilities. Precipitators or rural siting have long been standard for new capacity. Improvements in precipitation control or phasing out of the plant are fairly accepted practice for older units.

The new development in particulate pollution is that some regulations may demand the highest efficiency equipment on all units. The effect of such requirements on old commercial and industrial equipment used for heating or industrial steam production can be significant. They will increase greatly the pressure to retire older equipment.

Sulfur dioxide (SO_2) emission was clearly not seriously considered until recently; rural siting and high stacks would sufficiently disperse the gases. If, as it seems likely regulation of SO_2 emissions will cover all fossil fuel utilization devices, the impact may be quite substantial. Initially, during the first half of the seventies, utilities will increase the use of low sulfur content fuels. Based on present availability and price, this could mean a substantial increase in fuel costs. If these costs increased substantially, the lesser impact would be on those rates in which the fuel cost is a smaller portion of the total price (typically, smaller residential and commercial customers). A larger effect would occur in the case of large industrial and with off-peak rates, where the facilities component is a smaller portion of the total price.

In the long run, it is likely that some sort of commercially feasible SO_2 removal device will be developed. By 1973, this might be available for new units to go in service by 1977. The cost of such a device is uncertain; it has been suggested that a range of $25 to $50 per kilowatt of capacity is possible. The additional operating cost and even part of the capital cost might be offset by the sale of the by-product sulfur. Alternatively, nuclear power would solve this pollution problem as well as the particulate problem.

If SO_2 pollution is reduced, health and damage losses will be curtailed. However, any such reduction in SO_2 pollution will result in increased fossil fuelled generation costs either from higher priced "clean" fossil fuels, or as a result of major investments and operating costs of sulphur control systems.

A less defined area of air pollution control is that of nitrogen oxides. If regulation of emission of nitrogen oxides such as in Los Angeles were to be extended to the rest of the country, it would place a premium on types of energy production that do not involve combustion and on the development of nitrogen oxide removal facilities.

Finally, while the effects of carbon dioxide emissions have been under scrutiny, there is so far no consensus concerning any possible significant climatic effects. As total energy use expands, releases of carbon dioxide grow, but long range effects from any changes in the global balance are unclear and bear watching. Concern over carbon dioxide would favor non-combustion processes such as nuclear power generation.

Water Pollution Control regulations dealing with discharge of chemical or suspended matter will cause few additional problems in the generation of electricity. Involved here are the improvements in slag and ash handling, station waste, run-off from station properties, and disposal of material collected on filters.

The water pollution problem with the greatest impact on electric utilities is that associated with heat or thermal pollution. It is still unclear what exact form regulation of thermal effluent will or should take. However, it is quite likely that accommodating any likely regulations will involve additional capital investment for utilities in the form of special cooling facilities.

Radioactive Emission Control is of continuing concern because nuclear energy will be an increasingly important contributor to electrical capacity. While nuclear stations meet present radiation standards more than adequately, further restrictions may be imposed. Control of radioactive emissions to meet possible standards might add $1 to $5 per kilowatt to a 1000 megawatt plant cost.

In addition, it is likely that such additional restrictions will be applied to all operations in the nuclear fuel cycle. This might add slightly to the cost of fuel mining and manufacturing, and more substantially to the costs of reprocessing. In total, this should be reflected in no more than a 5% increase in fuel cost at the most. Such costs would not affect competitive energy sources.

Costs related to protection measures against possible radiation releases are not likely to continue to rise in relation to total costs. Licensing delays, additional safety systems, and more extensive inspection systems up to the present time have increased the costs of constructing and operating nuclear plants.

Aesthetic Considerations are of increasing importance. The siting of power plants has been the subject of much research and of federal and state legislative proposals. There have been several brochures and manuals prepared by federal agencies and private groups to aid in the reduction of the visual impacts on the environment. They are all in general agreement, so there is no need to report the suggestions here. There is, however, urgency in this matter.

The visual impact of large structures where the local populace does not want them is a matter in each case demanding individual resolution: there is little possibility of creating fixed standards that will be universally applicable. Generating plants are not alone in encountering such impasses; transmission lines are equally involved. As a result, it is sometimes difficult to decide whether there is in fact an unanticipated serious environmental problem, whether to fault the utility for bad judgment, or to accuse the neighbors of unabashed self-interest; it could be any of these, or some of each.

Power lines, long the center of some of our most celebrated conflicts, are unpopular everywhere, and particularly with those who must look at them, or make way for them in their own neighborhoods. There is always the conviction that they should "go somewhere else." But the unfortunate fact is that transmission lines are as vital to the supplying of society with power as energy generation. Lines can be shifted from one location to another, sometimes at additional cost, but in principle locations should be determined by the broad public interest rather than by which route is cheapest, or which party can garner enough force to shift the burden to his neighbors.

High voltage lines, today, cannot be placed underground for long distances, but the time will come, and in certain instances may not be too many years away, when transmission lines can be undergrounded (perhaps by conversion from AC to DC), and then much of the problem presumably will disappear. For the interim period, however, this Task Force suggests:

1. Transmission line construction should have advance planning and full review by public interests as well as by official regulators.

2. It is to be hoped that in the future there will be established at the state level a source of firm and final authorization to proceed after all review procedures are completed and any necessary and desirable alterations have been made.

3. Wide-circulation should be given two new documents now available to provide guiding principles on the best practices in location, design, and construction of power transmission lines. The Departments of the Interior and Agriculture issued in October, 1970, a publication entitled "Environmental Criteria for Electric Transmission Systems" for the use of their land management agencies and their federal power systems. The Federal Power Commission has published a similar set of guidelines "Electric Power Transmission and the Environment." These documents provide indications of the principles which will be used to guide federal practice in this field, but they also provide a basis for parallel regulation at the state level. They illustrate primary considerations in minimizing the aesthetic impact of transmission lines and related project works. It should be pointed out that utility organizations have themselves shown substantial initiative in developing and applying improved design criteria, and more of this should be encouraged.

There are other points of visual impact which also need attention. One of these—the undergrounding of distribution lines—has made remarkable progress since the situation was investigated by the Electric Utility Industry Task Force on Environment in 1968. In its report, the Task Force observed that the replacement of all overhead distribution lines would require an investment on the order of $150 billion, which of course made any such program wholly impractical. However, it was noted that:

"The industry generally supports the movement to place all new residential subdivision distribution lines underground. The Task Force expects that by 1975, no more new overhead distribution lines will be constructed in new urban and suburban residential subdivisions. The Task Force recommends that utilities, regulatory agencies, municipalities and developers cooperate fully in achieving this target date."

Since this recommendation was made, suppliers have perfected new equipment and materials which have greatly reduced the cost of undergrounding and increased its reliability. As a result of this, plus the action of Public Service Commissions in several states to spur undergrounding, many utility groups will do much better than reach the 1975 target date.

Fortunately, there has been a general trend among utility companies to beautify the many facilities that must, of necessity, be accommodated on the landscape. Structure design, architecture, landscaping, and general appearance have been greatly improved. There is no scarcity of models to follow.

- Plants have been carefully sited, thoughtfully designed, and often surrounded by parks and picnic areas.
- Sub-stations have been located where they are unobtrusive.
- Distribution sub-stations have been vastly improved, in some instances being contained within structures indistinguishable from others in the environment.
- It is not unusual for large utilities to have or retain architects and landscape architects, a practice that is gaining, and is doing much to give utilities a leadership rôle in the field of industrial beautification.
- New types of poles have been developed and transformers have been removed from sight.

Unquestionably, there is much more to be done, but the progress already made would indicate that the industry generally assumes a large measure of responsibility and further programs can be anticipated.

II. Meeting the Problem

Just as it is certain that substantial additions will have to be made to our generating capacity, so also it is certain that henceforth the siting and planning of new units will have to meet comprehensive environmental standards.

No longer will it be possible for a utility organization independently to choose an economically advantageous site for a plant and proceed to construct it. Ample lead time must be allowed so environmental factors can be studied thoroughly and reviewed in timely fashion with public agencies and responsible citizen conservation groups. The review process must start early,

since environmental laws and recent court decisions provide for review by many groups which may cause long delays or even the abandonment of construction plans. Experience proves beyond doubt that competent planning, comprehensive review, and firm legally-based powers of certification are necessary if the future need for facilities is to be met on anything like a planned schedule.

An essential ingredient in successfully meeting this problem is the establishment of official standards and criteria as guides for the industry to follow. To a great extent, this is being done, at least in principle. The development and institution of detailed standards in some cases must be a progressive process. Final permanent standards of a high level are the ultimate objective, but they may not be attainable under existing circumstances; therefore, so that essential units can come on line when needed, provision must in some cases be made for interim standards, subject to subsequent refinement. This is particularly necessary in power plant construction because of the very long lead times required. Signals cannot be changed on short notice. The Environmental Protection Agency states that "where standards cannot be met, we have acceptable methods of providing relief" and to the extent that such relief measures are practical, the problem is at least to some extent relieved.

All this is increasingly important in the face of constantly lengthening lead times in plant design and construction. Questions of environmental acceptability alone will require two to three years as an absolute minimum period for site selection, preliminary design, and timely review with official bodies charged with certification of projects, and with responsible representatives of the public. Four to five years additional will normally be needed for construction and start-up of fossil-fueled plants, or five to seven years for nuclear plants. The advance selection of sites and reporting of related environmental data ten years prior to expected use for commercial power supply, therefore, would seem to be a minimum safe forward-planning basis.

A recent report* issued by the Office of Science and Technology calls for:

(1) long-range planning of utility expansions on a regional basis at least ten years ahead of construction;

(2) participation in planning by the environmental protection agencies and notice to the public of plant sites at least five years in advance of construction;

(3) pre-construction review and approval of all new large power facilities by a public agency at the state or regional level, or by the federal government if the states fail to act.

Such an arrangement as this, desirable (and probably inevitable) as it is, suggests that future demand for power must be reasonably closely estimated approximately fifteen years in advance. This is no mean task in an environment with so great a technology thrust that a forward view of even five years in not taken without serious risk.

III. The Role of Research and Development

As previously indicated, this Task Force believes a vastly increased program of research and development in the electrical power field is essential.

The pressures of the environment make this far more important than ever before. The interaction between electric power supply and the environment is so pervasive that almost any progress in research and development in the field of power generation and transmission can be expected to improve directly or indirectly the environmental consequences of power supply. Stated more simply, it is reasonable to suppose that the more broadly efficient and successful is the process of power supply, the less will be its environmental consequences overall.

Two examples will demonstrate this point:

- Any advancement in thermal efficiency of either fossil or nuclear generation provides a double environmental gain. It reduces thermal and other waste discharges to the environment, and it conserves capital resources of natural fuels.
- The simplest improvement in equipment (switchgear, for example) helps make operations not only more reliable, but also more manageable insofar as the environmental impact is concerned. It also will produce economies, which in turn will make a small contribution toward the greatly increased financial effort required to meet the environmental challenges of the future.

* "Electric Power and the Environment," August 1970.

It is absolutely essential, in the opinion of this Task Force, that all power utilities and related industries, including private, investor, public, and cooperative elements, greatly increase their financial commitment to competent research and development. Many problems which are already clearly apparent must be faced, tackled and solved. Such a research and development program, to function properly, must be funded at a level several times the present rate of research and development expenditure in the industry. This fundamental need must be met by assessing the greatest portion of the cost against the rate structure. Obviously, this will require a firm policy directive on the part of the FPC, and full cooperation on the part of the various State Public Service Commissions, where the problems of rate regulation must be faced. These officials must recognize that reliability, the environment, and rates all are their responsibility, and are equal in their importance. This can turn out to be politically difficult.

The Task Force believes the basic need involves not only a commitment of greater financial support for research and development, but that an equally important need is to establish the institutional arrangements to spend the money wisely. Before such arrangements are created, it will be necessary to:

1. Develop and propose guidelines and priorities for research and development for the industry (private, public, cooperative and federal) geared to the future demands of the industry in terms of its performance requirements, demands on national resources, and relationships to the environment.

2. Translate these guidelines into detailed programs to be carried forward by appropriate entities through cooperative efforts with government agencies and other organizations.

3. Investigate the optimum organization and facilities needed to carry out research and development on such programs as:

(a) New long-range and mid-term developments of national, cross-industry significance designed to raise the technological level of the power industry's performance, increase its conservation of fuel and energy resources, and minimize environmental impact to the maximum possible extent.

(b) Expediting development of new power and new energy sources, as well as new transmission methods and techniques. This should include investigations of all possible alternatives to conventional generating facilities as we know them, including fuel cells, fusion, sun power, geothermal power, and direct conversion. It is suggested that most basic research should continue to be financed directly by the government and the industry should take the leadership in applied research and development.

(c) Various management approaches should be investigated, particularly as to the manner in which all affected segments, i.e., the power industry (investor-owned public, cooperative and Federal), public interests and the Government, will be represented and how they will interact in the selected management scheme.

The total estimated cost of such a project awaits a more thorough plan. However, its main support might come from an across-the-board service charge to add to such federal investments in research as are being made. A surcharge of .15 mills per kwh on all customers, for example, would produce an annual income of at least $200 million, and the largest part of the amount thus would be borne by the largest users, who could be expected to gain most from technological advances in the industry.

IV. The Need for Better Cooperation

There is need for better cooperation among the parties of interest in the power-environment conflict: the industry, the regulatory authorities, and the public.

Any freedom utilities may have had in the past to make unilateral decisions is gone; they must adjust to the facts of life in this respect. Some have. Some have not. All of them must accept official standards. None can afford to fight City Hall insofar as the environment is concerned.

Regulatory authorities, particularly those in the states, must recognize that they also have a new dimension in their responsibilities, and one that will alter their entire outlook. As guardians of the public interest in the past they have demanded reliability and have policed rates. They have felt a strong responsibility to prevent expenditures that were not directly related to the basic business of generating and distributing power. Today that has changed; they now must

accommodate a whole new category—and a costly category—of expenses. It is estimated that by 1990 more than $3 billion in capital expenditures could be required to achieve proper SO_2 emissions controls alone, and could add $1½ billion to operating costs and fixed charges in utilities across the country. The capital costs of water cooling facilities by 1990 could reach $9.7 billion, with an annual cost of $1.9 billion. In the case of new plants, air and water environmental protection will add an estimated five percent to total costs. Obviously, these costs must be allowable; they must be passed along to the power consumer, as well as other costs associated with environmental protection, and the costs of the badly needed stepped-up research and development. This will place a burden of great importance upon the regulatory agencies; not only must they police expenditures in this connection, but they also must police public demands so that desirable but unessential improvements are not forced upon the companies involved, to be paid for by a public that may have greater priorities for its funds.

To the extent that there will be unavoidable rate increases, a re-examination of the design of rates as well as their overall level has been suggested. Existing discounts to volume users might be reconsidered.

Working out the problems that inevitably introduces will require closer and more understanding relationships among the companies, the public, and the regulators than ever before. It does not suggest that the regulators give up their watchdog role on behalf of consumers; indeed, they will have to redouble their efforts. It does mean, to a large degree, that they will be called upon to exercise judgment and to mediate between environmental enthusiasts on the one hand and "the average consumer" on the other with the utility squarely in the middle.

The regulatory agencies also are likely to have an increasingly important role in rationing or in curtailment programs that might be required by shortages. This, too, will place a new and very heavy burden upon them.

One project in which the utilities, the regulators, and the public could well afford to work shoulder-to-shoulder is in demanding and securing a commitment on the part of the state that there will be firm land-use planning to govern the purposes to which specified areas will be put—and to insist that such plans be implemented. There are logical, practical sites for plants, and proper routes for transmission lines. Such areas are finite in number and can be determined only by an objective, informed analysis of all the factors involved in relation to other uses of land. There is no other way to resolve the many conflicting opinions that invariably arise when such decisions must be made.

The reasonable public must make its position felt so that policies will be set on the basis of sound environmental consideration, rather than out of recrimination. Initiatives in this direction must be taken in the first instance by the utilities. Political entities and regulatory authorities must concern themselves with equity—sometimes at the expense of political advantage. And it will help immeasurably if communications media made an honest effort to reconcile positions rather than exploit adversary positions.

The public and agency review process must start early, since environmental laws and recent court decisions in many instances pave the way for protesters to create long delays or even the abandonment of plans. Moreover, there is a proliferation of public agencies that now must be satisfied and which present many opportunities for the protestors to create further delays. Experience proves that competent planning, comprehensive review, and firm legally-based powers of certification are necessary if the future need for facilities is to be met on anything like a planned schedule.

An essential ingredient in successfully meeting this problem is the establishment of official standards and criteria based on valid scientific data as guides for the industry to follow, and it is commendable that several states are creating special official review groups with the power of final decision. In some cases this power has been given to the state utility regulating board.

There is a monumental public adjustment job to be done if there is to be any understanding; and without understanding, the situation will grow far worse before it improves.

V. A Footnote on Nuclear Power

The Task Force recommends that special attention be directed to nuclear power because it promises the best available answer to many of the existing environmental problems. In the

long run—or at least until entirely new methods become commercially practical—it would appear to be the least expensive means available for power generation. It conserves fossil fuels, and the breeder reactor, when it comes, will also conserve uranium resources. This is not to say that nuclear plants are without environmental problems. There is the question of the heated water discharges, the handling of irradiated fuel and the disposal of high level radioactive wastes, and the release (even though it is controlled) of low level radioactive wastes into air and water. Another factor which cannot be overlooked is the depletion of fossil fuels, which places an increasing burden on nuclear generation, and makes it doubly important to reduce the environmental impacts of the latter to the lowest practicable level.

It is possible, and even probable, that the environmental impacts of nuclear plants will be reduced further, and that waste heat, now one of the most serious problems, will find some practical uses, and will be reduced with the coming of breeder reactors. Accommodating waste heat at this time is possible, and is economically feasible. Programs for cooling are fully discussed in the Power Survey. If and when nuclear plants are brought into populated areas, where the load is heaviest, plant siting problems can be alleviated, and some of the troublesome overhead transmission will become unnecessary. Such plants, especially if put underground, can reduce environmental impacts that currently cause many problems with power generation by any method.

Nuclear power employs fissionable materials which yield inherently dangerous radioactive materials, and the rules and techniques for controlling these substances in a safe manner are frequently complex and difficult to express and understand. Furthermore, most nuclear generation units installed now and well into the 1980's will be so limited by technological problems in temperatures and pressures that their thermal efficiency will remain at about the present 30 percent overall. Thus, they discharge greater amounts of waste heat per unit of electricity delivered than the more efficient fossil-fired types, which may achieve up to 40 percent thermal efficiency. With such handicaps, the public may well ask, "Why bother with nuclear power? Why not continue to rely on present forms of power generation—hydro, coal, oil and gas-fired?"

There are three principal motivations for nuclear power, which are fully discussed in the 1970 Power Survey. Briefly: (a) hydro power is limited by available sites; (b) fossil-fired plants are limited by fuel availability, discharge of air pollutants, and, in many parts of the country, higher generating costs than nuclear plants; and (c) nuclear plants offer better solutions to overall environmental quality problems than typical coal and oil-fueled power plants. Thus nuclear power plants appear to offer more favorable advantages in several areas, including environmental aspects. The mission of insuring the safety and confidence of the public must and can be faced squarely.

This philosophy of weighing benefits against possible risks must be carried over to the individual citizen. It is clear that the description and analysis of possible radiological hazards from nuclear plants and their safety controls are often difficult for the layman to follow. In consequence, he must rely on evaluations and opinions of those presumed to be independent experts in the field. Thus it is disconcerting to find presumed experts differing on questions of alarmingly dangerous potential. There is no simple remedy for the public in these situations, except perhaps these precautions: (a) as far as possible, seek to rely on facts rather than offhand opinions; (b) where the judgment is made that a nuclear generation unit is not tolerable, judge this conclusion first by the demonstrated qualifications of the critic, and second by whatever constructive alternative is offered.

Questions dealing with the environmental aspects of nuclear power usually concern how man's air and water environments are affected by the potential release of radioactivity and discharge of heated water. Aesthetically, nuclear power plants are designed and built in a more pleasing manner than conventional plants.

The use of nuclear fuel avoids discharging of particulates, sulfur oxides, nitrogen oxides, carbon dioxide, carbon monoxide, and other products of combustion.

It would seem that the public's concern with regard to the potential safety of nuclear power really rests on the answers to the following questions:

(a) Has the best possible judgment been used in setting radiological safety standards?

(b) Do the benefits substantially outweigh the risks to public health and safety?

(c) Have the standards so established been met by the plants built and those now planned?

(d) What are the results? Has the public's environmental health and safety been preserved?

Expert opinion generally says "yes" to all the questions above. Obviously, however, there are differences of public opinion on the basis for saying "yes"—particularly to questions (a), (b), and (d). Hence, further elaboration is needed:

(a) The origins of present nuclear safety standards go back more than forty years to the establishment in 1928 of the International Commission on Radiological Protection (ICRP). A year later, the National Council on Radiation Protection and Measurements (NCRP) was formed, sponsored by the U. S. National Bureau of Standards. Some forty members, leading scientific experts in radiation science from fourteen countries, make up the ICRP. The radiation protection standards applied to nuclear power plants were developed by the AEC from the radiation health standards established by the world-recognized ICRP. In 1959, Congress created the Federal Radiation Council (FRC) to advise the President with respect to radiation matters and to provide guidance in these matters independent of the AEC itself.

The studies and recommendations of the ICRP and the FRC (whose functions are now exercised by the Environmental Protection Agency) are periodically reviewed, but continuously represent the highest scientific expertise to be found in the world in this field. Despite criticisms and alarms directed at the Atomic Energy Commission on its licensed limitations for radiation discharges, no comparable authority has levelled a creditable criticism at the fundamental health standards which were employed under guidance of ICRP and FRC.

(b) The licensed limitations imposed on nuclear power plants have been continuously and scrupulously followed. This is not a situation in which actual pollutions have exceeded desired or imposed standards under waivers or tolerated violations. Reports of the U. S. Atomic Energy Commission and independent inspections of the Public Health Service, HEW show that adherence to required limits has been consistent.

(c) The results in protection of public health and safety are attested by both positive and negative data. The most specific positive reporting is that contained in the reference studies of measured radiation effluents from operating nuclear power plants according to the Public Health Service. In general, the results show radioactivity releases to both air and water far less than those permitted by licensed limits, and at levels which often are indistinguishable from natural radiation background levels where the public might be exposed.

Tightening of physical limits on radioactive releases into air and water is technically possible. Individual states (notable Minnesota and Maryland) and other local jurisdictions believe that limits tighter than those set by the AEC should be imposed as long as these can be met. Even in the absence of any proven hazard to the public, it is argued that reduced limitations on radioactivity discharges will minimize certain consequences not yet fully anlyzed. These include:

1. Possible buildup of long-lived radioactive materials from multiple sources in atmospheric, terrestrial and aquatic ecosystems.
2. Possible reconcentration in the food chain of some radioactive materials, principally through aquatic organisms. The AEC standards allow for this possibility, and compensations are provided for certain radionuclides.
3. Presumptions of possible longer-term subtle but harmful genetic effects from low levels of radiation.

Within limits, it is possible and practical to further refine the designs of nuclear power systems to improve their safety limitations beyond today's standards. This is desirable not only in view of the increasing size of future units, but also as further reassurance to abate public apprehension. Nevertheless, reason must prevail so that a vitally needed and highly practical form of power generation can move forward in a rational manner.

The environmental problem of heated water discharges is not insurmountable. The problem is more severe in nuclear plants because of the lower thermal efficiency and corresponding higher heat rejection to air or water. Sometime in the 1980's—the earlier, the better—the commercial breeder reactor should bring two major environmental improvements:

(a) Reduced thermal effects because of higher thermal efficiency; and

(b) Conservation of uranium fuel by greatly increased conversion of fuel materials to electrical energy.

Meanwhile, nuclear power will fill a power gap that can not reasonably be met by other energy resources.

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GLOSSARY OF ABBREVIATIONS AND DEFINITIONS

Abbreviations

alternating current	ac	magnetohydrodynamics	MHD
barrels	bbls	mean sea level	Msl
barrels per day	bbl/d	megavolt ampere	MVA
British thermal units	Btu	megawatt	MW
cents	¢	megawatt hours	MWh
cubic centimeters	cm^3	million cubic feet	MMcf
cubic feet	ft^3	nitrogen oxides	NO_x
degrees Fahrenheit	°F	parts per million	ppm
direct current	dc	percent	%
electrogasdynamics	EGD	pound	lb
extra high voltage	EHV	pound per hour	lb/hr
gallons	gal	pounds per square inch	psi
gallons per minute	gal/min	pounds per square inch absolute	psia
gigawatt	GW	research and development	R&D
gram	g	reserve to production	R/P
Hertz	Hz	revolutions per minute	r/min
kilogram	kg	standard cubic feet	scf
kilovolt	kV	standard cubic feet per day	scfd
kilovolt-ampere	kVA	sulphur dioxide	SO_2
kilowatt	kW	thousand cubic feet	Mcf
kilowatt-hours	kWh	thousand cubic feet per day	Mcfd
liquefied natural gas	LNG	ultra high voltage	UHV

Definitions

ALTERNATING CURRENT (ac) — An electric current that reverses its direction of flow periodically (see FREQUENCY) as contrasted to direct current.

AMBIENT TEMPERATURE — Temperature of the surrounding cooling medium, such as gas or liquid, which comes into contact with the heated parts of the apparatus.

ANADROMOUS FISH — Fish, such as salmon, which ascend rivers from the sea at certain seasons to spawn.

BACKBONE TRANSMISSION SYSTEM — The principal portion of a transmission system to which other lines connect.

BACK-UP — Reserve generating capacity of a power system.

BASE LOAD — The minimum load over a given period of time.

BREEDER REACTOR — A nuclear reactor capable of producing more nuclear fuel than it consumes.

BRITISH THERMAL UNIT (Btu) — British thermal unit. A measure of heat energy. The quantity of heat energy required to raise the temperature of 1 pound of water 1 degree Fahrenheit, at sea level.

BULK DELIVERY POINT	A substation which receives power delivered at high voltage. Transformers at these points lower the voltage for power distribution.
BUS	An electrical conductor which serves as a common connection for two or more electrical circuits. A bus may be in the form of rigid bars, either circular or rectangular in cross section, or in form of stranded-conductor overhead cables held under tension.
BUSBAR	An electrical conductor in the form of rigid bars, located in switchyard or power plants, serving as a common connection for two or more electrical circuits.
CAPACITOR	A dielectric device which momentarily absorbs and stores electrical energy.
CAPACITY	The maximum power output or load for which a machine, apparatus, station or system is rated.
CAPACITY INTERCHANGE	In power pooling, transactions resulting from the assignment by participating utilities of reserve or excess generating capacity for common use.
CENTRAL STATION SERVICE	Refers to electric service supplied from an electric system rather than by self-generation.
CIRCUIT BREAKER	A switch that automatically opens an electric circuit carrying power when an abnormal condition occurs.
COAL SLURRY PIPELINE	A pipeline which transports coal in pulverized form suspended in water.
COINCIDENT DEMAND	Any demand that occurs simultaneously with any other demand; also the sum of any set of coincident demands.
COMMERCIAL PAPER	Short-term promissory note issued and sold by utilities and other companies usually through dealers in such paper.
CONDENSER	In a steam electric plant, a device which condenses steam into water after the steam has gone through the turbine before it is injected into the boiler for reuse.
CONNECTED LOAD	The sum of the capacities of the electric power consuming devices connected to a supplying system.
COORDINATION	Cooperative action by two or more systems to achieve the economies of overall power supply and network integration.
CRITICAL (as related to nuclear material)	The condition whereby an atomic chain reaction is capable of being sustained in a nuclear reactor.
CRITICAL STREAMFLOW	The amount of water available for hydroelectric power generation during the most adverse streamflow period.
DEMAND	The rate at which electric energy is delivered to or by a system or to a piece of equipment expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time. See LOAD.
DESALINATION PLANT	A water supply plant which removes salt from sea water or brackish water to produce potable water.
DIRECT CURRENT (dc)	Electricity that flows continuously in one direction as contrasted with alternating current.

DISPATCHING	The operating control of generating units, transmission lines, and other facilities including assigning of generator outputs as needed, controlling maintenance and switching operations, and scheduling energy transactions with other utilities.
DISTRIBUTION	The act or process of distributing electric energy.
DIVERSITY	The differences among individual electric loads resulting from the fact that the maximum demands of customers do not all occur at the same time.
ECONOMY ENERGY	Energy produced and supplied from a more economical source, substituted for energy that could have been produced by a less economical source.
EXTRA HIGH VOLTAGE (EHV)	Generally used to refer to voltages of 345 kilovolts or higher.
ENERGY	That which does or is capable of doing work, and is equal to average power multiplied by the interval of time.
ENERGY REQUIREMENTS	The amount of electric energy needed by a utility to serve its customers and to cover system losses.
FIRM POWER	Power intended to have assured availability to the customer to meet his load requirements.
FISSION	The release of energy through the process whereby the nucleus of an element captures a neutron and splits into two nuclei of lighter elements.
FORCED OUTAGE	The shutting down of a generating unit for emeregency reasons.
FOSSIL FUELS	(As used in this report) Refers to coal, oil, and natural gas.
FRANCIS-TYPE UNIT	A hydraulic turbine using vanes to drive generating equipment. Water enters the unit at a right angle.
FUSION	The combining of atomic nuclei of very light elements by collision at high speed to form new and heavier elements, resulting in the release of energy.
GASEOUS DIFFUSION	A method of isotope separation used to enrich uranium with the uranium-235 isotope. Based on the fact that atoms or molecules of different masses will diffuse through a porous barrier at different rates.
GENERATION, ELECTRIC	The process of transforming other forms of energy into electric energy.
GENERATOR	A machine which converts mechanical energy into electric energy.
GROSS NATIONAL PRODUCT (GNP)	The Nation's total national output of goods and services at current market prices.
G&T COOPERATIVES	Electric utility cooperatives which generate and transmit electric power usually at wholesale to distribution cooperatives and other member systems.
GIGAWATT (GW)	One million kilowatts.
HEAD, GROSS	The difference of elevation between the headwater surface above and the tailwater surface below a hydroelectric power plant, under specified conditions.

HEAT RATE	A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is the total Btu content of fuel burned or of heat released from a nuclear reactor for electric generation by per net kilowatt-hour generation.
HEAVY WATER	Water used in the moderation of nuclear reaction by certain types of atomic power plants. In this water (D_2O), the hydrogen of the water molecule consists entirely of deuterium—the heavy hydrogen isotope of mass 2.
HERTZ	Cycles per second
HOLDING COMPANY	A nonoperating company which controls other companies through stock ownership.
HYDROELECTRIC PLANT	An electric power plant in which the turbine-generators are driven by falling water.
INTERCONNECTION	A transmission line joining two or more power systems through which power produced by one can be used by the other. Also—intertie.
INTEGRAL TRAIN	Similar to unit train except that the cars are more or less permanently coupled.
INTERTIE	See INTERCONNECTION.
KAPLAN UNIT	A hydraulic turbine using propellor-shaped blades, which are adjustable under load, to drive generating equipment.
KILOVOLT (kV)	One thousand volts.
KILOWATT (kW)	One thousand watts.
KILOWATT-HOUR (kWh)	The amount of electrical energy involved with a one-kilowatt demand over a period of one hour. It is equivalent to 3,413 Btu of heat energy.
LIGNITE	A low grade coal of a variety intermediate between peat and bituminous coal.
LINE COMPENSATION	The balancing out of line impedance.
LINE IMPEDANCE	The apparent opposition to the flow of alternating current that is analogous to the actual electrical resistance to a direct current.
LOAD	The amount of power needed to be delivered at a given point on an electric system.
LOAD CENTER	The point in which the loads of a given area are assumed to be concentrated for purposes of analysis.
LOAD CURVE	A curve showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.
LOAD DIVERSITY	The difference between the sum of two or more individual peak loads and the coincident or combined maximum load, usually measured in power units.
LOAD FACTOR	The ratio of the average load supplied during a designated period to the peak or maximum load occurring in the same period.

LOAD GROWTH	The growth in energy and power demands by a utility's customers.
MARGIN	The difference between the net system generating capability and system maximum load requirements including net schedule transfers with other systems.
MEGAWATT (MW)	One thousand kilowatts.
MEGAWATT-HOURS (MWh)	One thousand kilowatt-hours.
MINE-MOUTH STEAM-ELECTRIC	A steam-electric plant built close to coal mines and usually associated with delivery of output via transmission lines over long distances as contrasted with plants located nearer load centers and at some distance from sources of fuel supply.
MULTI-PURPOSE RIVER BASIN PROGRAM	Programs for the development of rivers with dams and related structures which serve more than one purpose, such as—hydroelectric power, irrigation, water supply, water quality control, and fish and wildlife enhancement.
MULTI-PURPOSE TRANSMISSION LINE	Employment of a transmission line for more than one function, such as regular transmission, wheeling, reserve capacity, and peak capacity usage.
NUCLEAR ENERGY	Energy produced largely in the form of heat during nuclear reactions, which, with conventional generating equipment can be transformed into electric energy.
NUCLEAR (ATOMIC) FUEL	Material containing fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.
NUCLEAR POWER	Power released from the heat of nuclear reactions, which is converted to electric power by a turbine-generator unit.
NUCLEAR REACTOR	An apparatus in which nuclear fission is achieved in a self-sustained chain reaction.
OUTAGE	The period in which a generating unit, transmission line, or other facility, is out of service.
(IN) PARALLEL	Several units whose AC frequencies are exactly equal, operating in synchronism as part of the same electric system.
PARTICULATE MATTER	Solid particles, such as ash, which are released from combustion process in exhaust gases at fossil-fuel plants.
PEAKING CAPACITY	That part of a system's equipment which is operated only during the hours of highest power demand.
PEAKING LOAD	The greatest amount of all of the power loads on a system, or part thereof, which has occurred at one specified period of time.
PEAKING UNITS	Usually old, low-efficiency steam units, gas turbines, diesels, or pumped storage hydro used primarily during the peak load periods.
PLUTONIUM (pu)	A heavy, fissionable, radioactive, metallic element with atomic number 94. Plutonium occurs in nature in trace amounts only. However, it can be produced as a by-product of the fission reaction in a uranium fueled nuclear reactor and can be recovered for future use.

PONDAGE — The amount of water stored behind a hydroelectric dam of relatively small storage capacity used for daily or weekly regulation of the flow of a river.

POWER (ELECTRIC) — The rate of generation or use of electric energy, usually measured in kilowatts.

POWER FACTOR — The percentage ratio of the amount of power, measured in kilowatts, used by a consuming electric facility to the apparent power measured in kilovolt-amperes.

POWER POOL — Two or more electric systems which are interconnected and coordinated to a greater or lesser degree to supply, in the most economical manner, electric power for their combined loads.

PREFERENCE CUSTOMERS — Publicly-owned systems and nonprofit cooperatives which by law have preference over investor-owned systems for the purchase of power from Federal projects.

PRIME MOVER — The engine, turbine, water wheel, or similar machine which drives an electric generator.

PUMPED STORAGE — An arrangement whereby electric power is generated during peak load periods by using water previously pumped into a storage reservoir during off-peak periods.

REAERATION — The process whereby the oxygen content of water which has been depleted by heat from thermal power plants or by a deep position in a reservoir or otherwise is restored to normal level.

RESERVE GENERATING CAPACITY — Extra capacity maintained to generate power in the event of unusually high demand or a loss or scheduled outage of regular generating capacity.

RESIDUAL FUEL OIL — Oil remaining after the petroleum refining process is completed.

REVERSE-CURRENT RELAYS — A sensing device (relay) used to actuate some other piece of equipment, such as a circuit breaker, when the power flow changes direction along a transmission line.

REVERSIBLE CAPACITY — The characteristic of a single machine permitting it to be used alternately as a motor-pump or turbine-generator. It is therefore important for pumped storage developments.

SEASONAL DIVERSITY — Diversity between two or more power systems which occurs when their annual peak loads are in different seasons of the year.

SECONDARY HYDROELECTRIC ENERGY — Hydroelectric energy which is not available on a continuous basis under the most adverse hydraulic conditions contemplated.

SERIES CAPACITORS — A bank of capacitors connected in series with an electric power transmission line which are used to control the magnetic component of line impedance.

SERVICE OUTAGE — The shut-down of a generating unit, transmission line or other facility for inspection, maintenance, or repair.

SHUNT CAPACITORS	Capacitors connecting from a power line to a grounded connection, usually designed to reduce that part of the electric current causing a poor power factor.
SPINNING RESERVE	Generating units operating at no load or at partial load with excess capacity readily available to support additional load.
STANDBY EQUIPMENT	Generating equipment that is not normally used but is available, through a permanent connection, to replace or supplement the usual source of supply.
STEAM-ELECTRIC PLANT	A plant in which the prime movers (turbines) connected to the generators are driven by steam.
SURPLUS POWER	Generating capacity which is not needed on the system at the time it is available.
SYSTEM, ELECTRIC	The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management, or operating supervision.
TAP	A connection from one transmission line to another or to a substation.
THERMAL PLANT	A generating plant which uses heat to produce electricity. Such plants may burn coal, gas, oil, or use nuclear energy to produce thermal energy.
THERMAL POLLUTION	Rise in temperature of water such as that resulting from heat released by a thermal plant to the cooling water when the effects on other uses of the water are detrimental.
TIE-LINE	Transmission line connecting two systems.
TIME ZONE DIVERSITY	Diversity between systems in different time zones resulting from time difference as it affects the demands for power.
TRANSFORMER	An electromagnetic device for changing the voltage of alternating current electricity.
TRANSMISSION	The act or process of transporting electric energy in bulk (usually at 69 kVA or higher).
TURBINE	The part of a generating unit which is spun by the force of water or steam to drive an electric generator. The turbine usually consists of a series of curved vanes or blades on a central spindle.
TURBINE-GENERATOR	A rotary-type unit consisting of a turbine and an electric generator. (See TURBINE & GENERATOR)
TURN-KEY PROPOSAL	A job in which responsibility for all features of a development is undertaken by a single contractor.
UNIT TRAIN	An entire train used for one purpose such as to transport coal directly from coal fields to a generating plant.
VERTICALLY INTEGRATED SYSTEM	Refers to power systems which combine generation, transmission, and distribution functions.
VOLTAGE OF A CIRCUIT	The electric potential difference between conductors or conductors to ground, usually expressed in volts or kilovolts.
WATT	The rate of energy transfer equivalent to one ampere under a pressure of one volt at unity power factor.

WHEELING — Transportation of electricity by a utility over its lines for another utility; also includes the receipt from and delivery to another system of like amounts but not necessarily the same energy.

Sources: (1) Glossary of Electric Utility Terms prepared by Edison Electric Institute, 1961. Also EEI Nuclear Supplement (1961). (2) Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement, 1949 (GPO). (Prepared by a Subcommittee on Glossary of the Federal Inter-Agency River Basin Committee.) (3) FPC staff. (4) Nuclear Terms: A Brief Glossary. U.S. Atomic Energy Commission, 1964.

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